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December 1, 2014

Ms. Gina McCarthy, Administrator
U.S. Environmental Protection Agency
William Jefferson Clinton Building
1200 Pennsylvania Avenue, N. W.
Mail Code: 1101A
Washington, D.C. 20460

RE: Docket ID No. EPA-HQ-OAR-2013-0602 – Clean Power Plan

Dear Administrator McCarthy:

The Minnesota Department of Commerce (Commerce) and Minnesota Pollution Control Agency (MPCA) are pleased to submit the following comments on the U.S. Environmental Protection Agency's (EPA) proposed "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" rule (also known as the "Clean Power Plan") published in the *Federal Register* on June 18, 2014.

We applaud EPA's proposed rule approach, and believe it to be both good, and necessary, for the environment and the economy. While the proposal will not be sufficient to reduce emissions to fully address concerns associated with greenhouse gas emissions, it does represent a reasonable start for the power sector. Minnesota is proof that aggressive carbon emissions reductions from the electric power generation sector can be achieved while growing the economy, and we look forward to being a leader among states in addressing the requirements of the final Clean Power Plan.

As a state with an EPA-identified best system of emissions reductions, Minnesota will certainly continue its work to upgrade our electric generation system and reduce the carbon intensity of energy production. That said, we are concerned with certain aspects of EPA's rule, and had hoped it would have done more to put other states on the same clean energy path Minnesota has helped to develop. Instead, it appears as though the rule largely relies on clean energy leaders like Minnesota to make further reductions in carbon emissions to provide an overall level of national rule stringency while asking less of states with currently underdeveloped clean energy resources. Such a strategy may not take full advantage of the "low-hanging fruit" of carbon emissions reductions that remain available in many states, while seeking more aggressive reductions from states well-into their clean energy transition. The enclosed comments, though supportive of EPA's proposal, attempt to resolve some of these concerns.

We believe Minnesota is on a clean energy path that is generally consistent with EPA's plan, and clean energy efforts in Minnesota have already resulted in some 15,000 jobs accounting for over \$1 billion in annual wages. However, EPA's plan is likely to result in job shifts within the energy sector. EPA should work with states to help provide clean energy training opportunities where appropriate.

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We appreciate the opportunity to comment on the EPA's proposed Clean Power Plan. If you have any questions regarding the enclosed comments, please contact Bill Grant, with the Department of Commerce, at 651-539-1801 or bill.grant@state.mn.us; and J. David Thornton, with the MPCA, at 651-757-2018, or j.david.thornton@state.mn.us.

Sincerely,



Mike Rothman
Commissioner
Minnesota Department of Commerce



John Linc Stine
Commissioner
Minnesota Pollution Control Agency

JLS/MK:ld

Enclosures

cc: Janet McCabe, Headquarters, U.S. Environmental Protection Agency
Susan Hedman, Region 5, U.S. Environmental Protection Agency
Beverly Heydinger, Minnesota Public Utilities Commission
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Minnesota's Comments on the Proposed Clean Power Plan

December 1, 2014

Stringency and Methodology of the Clean Power Plan Proposal

Minnesota supports the national stringency and general methodology of the Clean Power Plan

We support the proposed Clean Power Plan's effect of reducing nationwide carbon dioxide (CO₂) emissions 30% (from 2005 levels) by 2030. This reduction is complementary to Minnesota's current commitments to reduce CO₂ from its power generating sector, and we encourage the U.S. Environmental Protection Agency (EPA) to retain the stringency of its proposal.

Minnesota supports EPA's general approach to determining the Best System of Emission Reductions (BSER), and is pleased that EPA acknowledged Minnesota's efforts in implementing each of the "building blocks"—heat rate improvements at coal fired power plants, expanded use of natural gas combined cycle (NGCC) generation in lieu of coal-based generation, and growing renewables; expanded renewable energy (RE) generation and use of demand-side management tools like energy efficiency (EE) programs to reduce the demand for electricity generation of all kinds.

We also support the flexibility provisions of the proposal that allow states to determine their own best system of energy planning as they develop compliance strategies. This flexibility is especially important as it will allow states in their energy planning to balance CO₂ reductions with reliability and economic considerations.

Minnesota appreciates that EPA is considering multiple alternatives for the building blocks as it develops its final rule. While the provisions of the final rule remain uncertain, we believe that EPA's original proposal is reasonable and achievable for Minnesota, provided EPA:

- Incorporates the technical corrections identified in Minnesota's September 16, 2014, letter (see attachment 1);
- Ensures that, for compliance purposes, states compelling RE production in another state are able to use the energy produced; and
- Ensures that new, imported hydroelectric power may be fully counted for compliance purposes.

Minnesota will, of course, achieve the Clean Power Plan targets by utilizing a different building block combination than that identified by EPA, relying more heavily on the use of RE and less so on NGCC. Regardless, we support of this proposal.

Providing a rule framework that facilitates regional approaches to state planning is critical to the success of the Clean Power Plan. A regional approach for compliance with the Clean Power Plan will recognize the relationship between a state's responsibility to achieve emission reductions from the electric generation sector and the regional electricity market in which affected units participate. We strongly encourage EPA to ensure that the final rule removes any barriers to multi-state planning and enable efficient regional planning approaches.

At this time, we do have concerns regarding some aspects of the proposal – including certain aspects of BSER calculations, treatment of post-baseline actions for compliance planning, and strategies for interim target setting - and have provided comment on those and other issues below.

In EPA's Notice of Data Availability (NODA) (79 FR 64543), EPA sought comment on a number of additional issues identified by stakeholders in early comments on the proposal. Minnesota appreciates EPA's efforts to carefully consider all stakeholder concerns, and requests similar deliberation of Minnesota's comments.

Alternative Building Block Targets

Minnesota supports EPA's goal to increase the use of renewable energy in the U.S. Based on current requirements and energy plans, Minnesota expects to generate 28.5% of its electricity using renewable sources by 2030. Minnesota's recent renewable energy integration study conducted by GE Energy Consulting for Minnesota energy planners indicates that it is technically feasible to generate up to 40% of Minnesota's electricity from renewable sources (see attachment 2).

The Clean Power Plan's alternative RE proposal, however, would have a significant impact on Minnesota's final target without reasonable adjustments as noted below. Minnesota – already a clean energy leader in the U.S. – would be expected to reduce the carbon intensity from its base year emissions by more than half, and do so within little more than a decade. Minnesota believes that a 2030 final reduction goal of 700 lb/MWhr resulting from the alternative RE proposal could be problematic – this is the CO₂ emissions rate achievable by a new NGCC, but little else.

Minnesota believes the alternative RE approach would be more reasonable and better represent BSER if additional adjustments can be included in the final emission guidelines:

- EPA must incorporate the technical corrections identified in Minnesota's September 16, 2014 letter.
- EPA should ensure that new, imported hydroelectric power may be fully counted for compliance purposes.
- EPA should reconsider NGCC capacity factors for states, like Minnesota, with higher RE potential to reflect the role played by NGCC in backing up RE generation. Minnesota will further address this proposed reassessment of NGCC capacity in comments below.
- States like Minnesota, which have paid for RE located in other states, should receive full compliance credit. Minnesota rate payers rely on RE to reduce reliance on fossil fuel generation and should not be expected to bear additional compliance cost burdens for carbon emissions reductions they have already paid for.
- EPA should allow states to include new NGCC in compliance calculations, thereby expanding the pool of available mitigation options and lowering compliance costs.
- Finally, for reasons of burden-sharing, EPA should adopt a minimum performance level requirement for coal-fired EGUs commiserate with a 20% reduction in emissions intensity for coal. This value is about 1.75 lb/kWh. Minnesota recommends this in place of EPA's proposed reassignment of NGCC capacity to states currently without NGCC.

NGCC Capacity Factors Under the Alternative RE Approach

If EPA uses the Alternative RE approach in the final rule, where expected RE generation is substantially increased for many states in EPA's determination of BSER (and targets therefore made considerably more stringent, as indicated in comments above), the reliance on a 70% NGCC capacity in building block 2 target-setting calculations for Minnesota and other states with similar generation profiles should be reconsidered.

EPA's current assessment of NGCC in building block 2 may overlook the role NGCC units have in support of wind and solar power. Minnesota relies on NGCC units to provide energy during peak consumption periods, and in part as backup for wind energy. Minnesota is concerned whether our existing NGCC, run as baseload plants with capacity upward of 70%, could additionally fulfill their existing role in supporting RE generation and peak load service. With current RE generation of about 10,000 GWhr, it might be reasonably expected that with whatever role NGCC plays in backing up its wind resource, under the alternative RE approach that expects Minnesota's RE generation to increase to 18,647 GWhr, Minnesota's reliance on its existing NGCC capacity to back up RE will increase.

Minnesota recommends that if EPA finalizes the alternative RE approach, it re-visit NGCC capacity factors on a state-by-state basis to refine state targets. We encourage EPA to closely review comments from the Midcontinent Independent System Operator (MISO) (and all other independent system operators and regional transmission organizations) regarding actual utilization of NGCC for states and regions as it reconsiders NGCC capacity.

Transmission costs under the Alternative RE Approach

With current RE generation of approximately 10,000 GWh and Minnesota's current renewable energy standard (RES) requirements for future years, EPA's alternative RE goal is not an unreasonable projection of renewable potential for Minnesota, if production tax incentives for renewable energy remain in place, economic growth continues, and the cost of renewable energy continues to decline relative to the cost of other resources. Minnesota ratepayers have already made significant transmission investments to enable Minnesota utilities to reach the state's RES requirements. For the State to be able to reach the alternative RE target level of RE generation, an evaluation of additional transmission investment may be needed. Significant additions of renewable energy could require either additions of more transmission capacity, different configurations of transmission facilities, or both. If EPA finalizes the alternative RE approach, it should ensure that final assessment of building block 3 consider transmission costs.

Post-Baseline Considerations

EPA must better support early efforts to reduce carbon emissions for Clean Power Plan compliance

EPA should credit all emission reduction actions occurring after the 2012 base year. Failure to do so creates an incentive for states to delay emission reduction measures so they will "count" for plan compliance (thereby delaying actual reductions of CO₂) and is unfair to states and utilities with active, on-going clean energy programs. Additionally, EPA should allow states to recognize emissions reductions from existing (pre-2012) programs to the extent that these program measures continue to provide quantifiable emissions reductions.

Compliance Deadlines and Interim Targets—The 2020 to 2029 Glidepath

Minnesota supports EPA's proposed 2030 compliance deadline, but believes the interim goal approach should be modified

Achieving EPA's proposed final target will require significant shifts in generation as well as additional transmission. Minnesota believes that while aggressive, the year 2030 is an achievable compliance deadline, assuming EPA incorporates changes provided on page 1 of this document.

However, Minnesota believes the proposed interim goal requires reassessment. In its current form, the interim goal is too restrictive because the timing does not allow for orderly energy planning. The interim goal fails to account for the manner in which large energy generation shifts generally occur and is at odds with Minnesota's energy planning processes. The interim goal is too strict, and as a result limits Minnesota's flexibility in choosing how to meet the interim and/or final reduction goals.

EPA's integrated planning model (IPM) predicts Minnesota closing 1600 MW of coal-fired generation by 2030. To replace such large generation resources, Minnesota utilities will need to consider all types of generation. Such large generation shifts are not yet identified in utilities' current integrated resource plans (IRPs). The effort to accomplish those shifts includes generation resource planning, design, financing, permitting and construction, not only of generation, but potentially additional transmission lines and natural gas pipelines. EPA's alternative RE goal could require even further additional transmission investments – the nature of wind generation and Minnesota's load would require construction of transmission lines so that nighttime generation could be transferred to the east. If no longer able to "sink" energy to the east, we would likely be required to curtail more generation.

For a long-term average interim target whose compliance period begins in 2020, it will be difficult for states to achieve the emission performance required by EPA's interim targets set by EPA's building block assembly. Setting a stringent interim target that includes an average of emissions performance beginning in 2020 would then require states to over-control beyond the interim value to offset any year's emissions rates above the value – possibly controlling to a level even below the final target value. Because of this, states would essentially need to be achieving emissions rates close to the interim target by 2020. Minnesota has reduced the carbon intensity of its energy fleet substantially, but we began our efforts nearly 15 years ago; EPA's current interim approach affords us insufficient time to implement significant changes to Minnesota's electric generating fleet.

In Minnesota, achieving the final goal and shifting generation as described above will likely result in large "step changes" in emissions, not a gradual reduction as the proposed interim goals seem to assume. This step function of emissions progress must be determined in long-range planning that considers how investor-owned utilities will need to modify IRPs to help achieve Minnesota's final goal. These step changes and the long-term planning needed to produce them necessitate state-level involvement in the creation of any associated interim targets.

We recommend that in place of EPA adopting its own numerical value interim goal for each state, EPA should instead apply the structure it has adopted within the regional haze rule (40 CFR 51.308 (d)(1)) for ensuring reasonable progress. Under the regional haze program adopted by EPA, the state, not EPA, is responsible for establishing the reasonable progress goals as a part of its Regional Haze State Implementation Plan, and is directed to establish goals that represent progress without backsliding. The regional haze program allows the state to assess the cost of compliance, and then determine the rate of progress needed. The goals established by the state are not federally enforceable, but are considered by the Administrator and then approved when the Administrator evaluates the adequacy of the state's plan. Alternatively, or as a part of allowing states to set their reduction goals, an interim goal that reflects an average emissions rate from 2012 to the final goal would more appropriately take into account the timing of measures to be implemented to achieve final reduction goals.

In EPA's NODA, EPA requested comment on a plan for phasing in building block 2 on the basis of how quickly additional infrastructure improvements could be developed to support NGCC (79 FR 64552). Based on Minnesota's experience with its nearly-completed major transmission upgrades called CapX2020¹, some transmission projects could take nearly the entire compliance time period to complete. This further supports a rationale for allowing states to set their own interim targets as a part of their planning process, as states would be in a better position to assess state and regional infrastructure improvement impacts on interim compliance progress. This approach also fully recognizes state energy planning processes in Clean Power Plan implementation.

Minnesota strongly supports the use of state-identified interim targets, rather than the approach identified by EPA in its proposal. We understand, however, the concern that some states may fail to set a reasonable interim goal (or any goal at all). For such situations, EPA could rely on their proposed interim target approach as a "backstop" to ensure reasonable progress on a state-by-state basis.

If EPA is unwilling to adopt Minnesota's recommended approach, we would suggest that, at a minimum, EPA modify the 2020-2029 averaged interim target and instead identify a single-year interim target (e.g., 2025) level of performance. A reasonably set single-year target would avoid the problem identified above of having to offset performance above the interim target value with proportionate performance below the target value.

¹ <http://www.capx2020.com/>

Hydroelectric and Nuclear Power Generation Considerations

New hydroelectric power should be allowed to be included for compliance crediting in a state's plan

Minnesota utilities have entered into agreements to deliver Canadian hydroelectric power as a significant part of their resource mix. Minnesota expects that EPA's final rule will allow states to include expanded hydroelectric power in the compliance calculations. Expanded power could be achieved with additional capacity obtained through the development of new power at existing power facilities, or the purchase of previously unused Canadian power.

Minnesota agrees with EPA that hydroelectric power generation should be available for use in compliance determinations as a zero emissions energy source. Hydro is also able to quickly respond to changing wind and solar generation, and is a reliable source of power. The Department of Energy (DOE) is suggesting that the United States could increase hydroelectric power capacity by 15% by retrofitting existing dams with power generation; by allowing "new" hydroelectric power—that is, the expanded use of hydroelectric power in a state's compliance plan, EPA will also provide incentives for developing these small hydro generation projects. According to the 2012 Oak Ridge National Laboratory study conducted for the DOE, Minnesota has the potential of 186 MW of generation at existing dams that are currently without power².

Within the compliance period of this rule, Minnesota will also begin the planning process for replacing up to 900 MW of nuclear generation. It is important to allow states to consider expanded contracts of hydroelectric power from Canada as a means of replacing one zero-emitting generation technology with another. If EPA adopts its proposed alternative approach for renewable energy targets as described in this rule's proposal, Minnesota will have even more zero-emitting generation to secure. Minnesota recommends that EPA affirmatively state that hydroelectric power installed nationally and internationally post-2012 may be included in a state's plan.

Treatment of Nuclear Power Generation

States with existing nuclear capacity are penalized in the calculation of emission rate goals. Under EPA's approach, states with nuclear power are left with a more stringent emission rate goal relative to states that do not employ nuclear power because of EPA's inclusion of the 6% "at risk" generation factor in the calculation of state goals. We recommend that this factor be dropped in the determination of states' CO₂ compliance goals.

Renewable Energy

Minnesota's renewable energy leadership should be reflected in the State's goal calculation

Minnesota has led on renewable energy goals and laws since the early 2000s. In 2001 the Minnesota legislature enacted the Renewable Energy Objective (REO), which required electric utilities to make a good faith effort to ensure that at least one percent of the energy the utility provides to Minnesota consumers is generated by an eligible renewable energy source by 2005, and to increase this amount to 10 percent by 2015. In 2003 the REO was modified from a goal to a requirement for Xcel Energy, the largest electric utility operating in the State. The 2003 legislation also authorized the Minnesota Public Utilities Commission to establish a renewable energy credits trading program for the REO, whereby utilities could purchase certified renewable energy credits rather than generate or procure the renewable energy directly.

In 2007, Minnesota enacted the Next Generation Energy Act (NGEA). The NGEA created, among other programs, a Renewable Energy Standard (RES) that requires Minnesota utilities to acquire renewable energy equal to 25% of retail electricity sales by 2025 (Xcel Energy must reach 30% renewables by 2020). In 2013 a 1.5% Solar Energy Standard (SES) by 2020 was enacted for investor-owned utilities. The SES statute also includes a 10% solar goal for 2030.

² http://nhaap.ornl.gov/system/files/NHAAP_NPD_FY11_Final_Report.pdf

Minnesota's early action to spur renewable energy development prior to 2012 must be reflected in the State's interim and final goals. Minnesota's ratepayers have made significant transmission and RE facility investment to build the State's renewable energy portfolio to what it is today. This investment is seen in EPA's assumed RE level data in the alternative RE generation quantification approach: while the renewable energy resources available to Minnesota are similar to the natural resource conditions in our neighboring states, Minnesota's effective RE level under the alternative RE approach is 20 to 30 percent higher than the effective RE levels found for Minnesota's neighbors. To the extent that the effective RE levels and targets impact a state's interim and final goals, early adoption of RE through aggressive state policies should not result in a state's goal being made more stringent.

EPA must allow states to use renewable energy credits (RECs) like that provided by the Midwest Renewable Energy Tracking System (M-RETS) to track and account for renewable generation

Based on data from MISO, the M-RETS system tracks the amount of renewable energy that is actually delivered to the integrated transmission system. Each megawatt hour of renewable power produces a REC. Owners of RECs can use the RECs for various purposes, such as selling the RECs or complying with state RPSs. In any case, M-RETS allows each REC to be used only once, for a specified purpose.

The RECs may belong directly to the owner of the generation facility or to another entity that purchases the renewable power through a contract such as a power purchase agreement (PPA). Once the owner of the REC "retires" the REC in M-RETS for a specified purpose such as compliance with the Minnesota RES, the REC may not be used again. As such, M-RETS ties renewable energy production to a specific entity, no matter where the renewable energy facility is located.

Minnesota's current RES allows utilities to bank RECs for up to four years to allow utilities the practical flexibility needed to plan for the "lumpiness" of large renewable energy projects with long planning, development, and construction lead times. The four-year REC banking system also allows utilities to match variable renewable resources with variable load that typically occurs with fluctuations in weather, so that generation in excess of goals from a high wind year may offset generation deficits in a low wind year.

EPA must be clear in its final rulemaking how a state like Minnesota could rely upon RECs tracked in M-RETS, and whether any additional information or changes to the system would be required for Clean Power Plan compliance purposes.

EPA should make it clear that States that implement RE measures receive the credit, regardless of where the generation resource is located

EPA has included RE physically generated outside of Minnesota but "counted" under Minnesota's RES in their calculations of those other states' Clean Power Plan emission rate targets. EPA should include language in its final rule making clear that states compelling newly built (post-proposal) renewable generation receive credit towards their compliance demonstration. The MPCA's understanding of the proposed rule's treatment of RE resources comes from *State Plan Considerations TSD*, which indicates that a "state that implements the measure – i.e., end-use energy efficiency and renewable energy regulations or programs, or an emission limit that addresses out-of-state generation – claims the avoided CO₂ emissions, regardless of where they occur." Explicitly stating in rule language that States (and the retirement of the associated RECs) receive credit is necessary for stable RE planning.

To meet this goal, Minnesota recommends that EPA continue to use this approach, by allowing the utility to count toward Minnesota state plan compliance the actual RECs from renewable energy production that the utility retires in M-RETS toward Minnesota's RES, regardless of where the RE facilities are located. This system also allows utilities to count portions of production from a renewable facility toward more than one states' RPS; however, each REC associated with

one MWh of renewable energy production may be counted only once. As a result, a system such as M-RETS allows for reasonable flexibility and verifiable compliance.

The most cost-effective location for renewable energy may be in another state; under M-RETS, utilities may claim ownership of such renewable energy only by ownership of the generation facility or by contract such as a PPA. Because M-RETS tracks (1) the amount of renewable energy delivered to the interstate transmission system and (2) the amount of renewable energy that the utility retires for each state, and since RECs may be used only once, Minnesota recommends that M-RETS or an equivalent system be used for state plan compliance.

Not only would this approach allow for the most cost-effective approaches for state plan compliance, allowing continued use of a system that is already in place for RPS compliance would remove the current unintended effects that uncertainty about state plan compliance is having in delaying cost-effective renewable energy additions to utility systems. For example, a multi-state utility recently delayed any addition of 300 MW of wind that was shown to be cost-effective because it was not clear how the location of the wind facilities would affect plan compliance in various states.

Voluntary green power programs should not be counted toward utility compliance with the Clean Power Plan

Almost all Minnesota utilities offer some form of voluntary program whereby ratepayers may pay a premium to source their energy consumption from renewable generation to go above and beyond the minimum requirement set by the state. To ensure the RE sought by participating ratepayers is in addition to that already compelled by the State, Minnesota does not allow green pricing RECs to count toward the State RES. Minnesota utilities must create separate REC retirement accounts to avoid counting green pricing RECs toward the utilities' MN RES or other state's RPS and green pricing programs. Similarly, if it were possible that the renewable power for which customers were paying a premium would have been acquired by the utility anyway for compliance with the Clean Power Plan, this would undermine the main attraction of green pricing programs.

EPA should ensure that the final rule includes language clarifying treatment and compliance crediting of waste-to-energy (WTE) facilities

Minnesota believes that when EPA calculated RE already being generated in a state, they counted all of the electricity from municipal WTE facilities as renewable, making no effort to separate or discount the electricity generated. We encourage EPA to provide clarifying language regarding the quantification of eligible electrical output from these facilities.

Energy Efficiency

Credit for Emissions Reductions on EGUs outside of Minnesota

Under Minnesota Statutes §216B.241 subd. 1c, all Minnesota electric utilities are subject to an annual energy savings goal of 1.5% of annual retail energy sales, excluding sales to customers that have opted out of utility-administered EE programs.³ Many utilities have one or more qualifying EGUs located outside the state. Thus, end-use efficiency measures within the Minnesota service territories of these utilities may result in emissions reductions at EGUs located outside of Minnesota. Nonetheless, the full savings realized by these EE measures are credited to the utility and applied toward their 1.5% savings goal. For compatibility with existing state law and because the incentives and related program expenses incurred by the utility are wholly funded by Minnesota ratepayers, we feel that Minnesota should receive full credit for savings realized at out-state EGUs under 111(d). Such treatment of EE savings would be consistent with expected treatment of out-of-state RE generation compelled by Minnesota.

³ See Minnesota Statute 216B.241, Subdivision 1a. for details regarding large customer facility exemptions from CIP.

For reasons of equitable burden sharing among states for goal setting and expedited emissions performance, EPA should accelerate the rate at which states ramp up to EE goals of 1.5%

Minnesota's experience has shown that EE programs can be developed and intensified relatively quickly. The rate of increase in energy savings in Minnesota's electric power system went from 0.8% to a required 1.5% between 2007 and 2010. EPA should consider similar ramp-up rates for states that have yet to achieve a level of 1.5% energy savings.

Data Collection and Reporting Requirements

Minnesota's automated software solutions for EE data management and reporting, developed to enable achievement of State policy goals, are also conducive for enabling effective data management and reporting under 111(d). We urge EPA not to designate the use of specific software that would undermine the work that we have done to improve the accuracy and efficiency of EE data collection in the state. While minimum reporting requirements should be expected for data collection and reporting, we encourage EPA to review existing state reporting programs to help set such minimum requirements. We are happy to provide EPA with more information on ESP® (also discussed in attachment 3) or a demonstration if it would be helpful.

Gross vs. Net Savings

As EPA is aware, states generally require that EE savings be expressed as net savings, gross savings, or both. Gross savings reflect the savings realized by the efficiency improvements irrespective of the customer's motivations for making the improvement. Net savings represent the savings achieved by the program after subtracting out "free-riders" (customers that would have made the EE investment without the influence of the program), sometimes adding in market "spillover" effects to non-participants, and removing the influence of other programs or exogenous factors. While the definition of net savings is commonly understood, the factors included in net savings evaluations vary by state. This makes it difficult to compare net savings across states. Net savings are also very sensitive to the evaluation methodologies and input assumptions employed by each evaluator. In contrast, gross savings are relatively straightforward to evaluate. Technical Reference Manuals and other resources provide standard methodologies for calculating gross savings, and standard protocols such as the International Performance Measurement and Verification Protocol are commonly used across the industry to measure and verify gross savings. For these reasons, Minnesota strongly encourages EPA to require reporting of gross savings under 111(d).

If desired, EPA could require reporting of "adjusted" or "verified" gross savings under 111(d). Adjusted gross savings represent the gross savings achieved by a program after installation and operational information on the EE measures are collected through site visits, sub-metering, billing analysis, customer surveys, and other techniques through a third-party impact evaluation. If evaluated correctly, adjusted gross savings are the best estimate of actual physical savings realized. Although Minnesota does not currently require third-party impact evaluations, we are open to this approach under 111(d) as long as the requirements do not entail excessive Evaluation, Measurement and Verification (EM&V) costs. We suggest that EPA cap EM&V costs at 5% of total EE spending in determining EM&V requirements and guidelines.

Inclusion of non-utility EE

EPA should encourage states to develop a clear path for inclusion, crediting, and administrative review and oversight of non-utility-delivered energy efficiency activities providing emissions reductions included in state plans. This may include energy savings performance contracts, low-income weatherization programs, industrial energy efficiency and other privately contracted and delivered energy efficiency historically unaccounted for in ratepayer and state programs. EPA should afford great deference to state energy efficiency programs and policies and allow states to credit energy efficiency programs and policies that utilize EM&V protocols and standards (as outlined in attachment 3). EPA should acknowledge and support state program competency in energy program design and delivery. State energy efficiency program experience, energy savings goals, and structures have varied based on state circumstances.

Additional Considerations from the Notice of Data Availability

EPA published a NODA on October 30, 2014, seeking specific comment on a number of additional proposals and/or issues identified in the original proposal. We must note our frustration with the late-issued NODA, which provided several significant rule alternatives for consideration, but with no additional time for review/comment, and no additional data provided to assist States in their review. Without additional time and data to review NODA alternatives, it is difficult for Minnesota to fully understand and address its impacts at this time. Though certain items in the NODA are addressed in comments above, Minnesota addresses some additional proposals below.

EPA should consider alternatives to the 2012 base year only for anomalous units

The NODA solicits input regarding whether a different single data year or average of a combination of years should be used to calculate a baseline for use in state goal calculations. Minnesota believes that 2012 is generally an appropriate base year, and should remain the presumptive base year for most units in most states. For units whose operation in 2012 was anomalous, states should select an appropriate three-year average for use in baseline calculations. Providing the opportunity for states to select years would better ensure the use of data more reflective of the unique circumstances of these particular units. Requiring such data to be in the form of a three-year average would lessen the likelihood that a state could simply select the highest-emitting year for a particular unit. This approach could address, for Minnesota the concern with Sherco Unit 3 identified in our September 16, 2014 letter, and may address concerns for other units whose 2012 operation was also anomalous. EPA should issue an additional NODA or supplementary proposal providing this option, and allowing states the opportunity to submit appropriate three-year average baseline information for anomalous units. Final goals would incorporate data for these anomalous units.

EPA should not assign a CO₂ value to RE and EE in order to re-assess building blocks 3 & 4

In the NODA, EPA discusses some stakeholders' interest in assigning a CO₂ value to RE and EE (79 FR 64552) and suggests alternative means to determine a value. EPA first asks for comments on the assumption that RE and EE replace fossil generation, either proportionately, or fossil steam first.

It appears to be erroneous to assume that additional RE and/or EE will replace in-state fossil generation directly; Minnesota has recently completed a study to determine how to integrate additional renewable energy into its current electricity generation system, up to 40% of all generation. The study, prepared for Minnesota by GE Energy Consulting, is provided in attachment 2. This study indicates that for Minnesota, additional RE will not simply displace in-state fossil generation (coal and gas) but rather, will displace resources on the margin, including imports from outside Minnesota. Given this, it is reasonable to assume that each state will be different, and thus subject to different impacts or effects of adding new RE generation, or EE savings, to a state's mix of generation. In order to appropriately assign a CO₂ value to RE and EE, a state would need to know what resource was at the margin at the time (which involves hour to hour variations) the RE or EE energy was created, or EPA would have to come up with some marginal emissions factor. Very few studies exist on marginal emission factors in the US, and EPA would likely have to conduct foundational research into this matter. Given the time constraints associated with the Clean Power Plan and the complexity of research needed to accurately modify the building block 3 and 4 calculations, Minnesota recommends that EPA treat RE and EE as originally proposed.

Additional Considerations on the Rate to Mass Translation Notice of Additional Information

EPA published a notice on November 13, 2014, detailing a possible method for translating emission rate-based CO₂ goals to their mass-based equivalents. The late issuance of this information makes it difficult to fully analyze EPA's suggested method; however, we note our general interest in a workable method for translating rate-based goals to mass-based goals. A mass-based goal appears to be able to simplify much of the compliance work associated with this rule – particularly if states were to choose to implement trading programs (single and/or multi state) for compliance. However, we are concerned that the method identified by EPA in its November 13 notice seems to increase the stringency of

Minnesota's final target from the rate-based goal identified in the original proposal. We believe that the rate-based target would require an approximately 40% reduction in CO₂ emissions, while the mass-based method identified by EPA would result in a 50% or greater reduction. This discrepancy in stringency resulting from EPA's translation methodology is of considerable concern for Minnesota, and likely for many states. If approvability of mass-based targets in state plans is dependent upon some level of adherence to EPA's calculation method, we believe that the mass-based approach could simply cease to be a viable option for many states – thereby eliminating much of the flexibility upon which success of EPA's Clean Power Plan is based. EPA should either be very flexible in considering state methodologies for rate-to-mass target calculations in its plan review process, or should simplify its methodology and ensure that it results in equivalent stringency between the two approaches.

State Plan Considerations

Initial state plan submittal procedures

Multi-state plans and quantifications

EPA's proposal (70 FR 34915) indicates that only one multi-state plan would need to be submitted on behalf of all participating states. Please clarify expected procedures for initial (June 30, 2016) submittals. Will states expecting to participate in multi-state plans be expected to submit individual preliminary plans, or joint plans? Please also clarify EPA's expectation regarding the "initial quantification of the level of emission performance," and indicate whether EPA expects different levels of analysis based upon whether a state expects to participate in a single or multi-state plan. For a multi-state plan, state-level quantifications of emissions performance may be difficult to produce by mid-2016 (or ever, depending on whether a region were to create a trading program or other system where performance is dependent upon regional operations that may vary throughout the compliance period). Minnesota recommends that EPA require one (joint) submittal on behalf of all states expected to participate in a multi-state plan, for both initial and final plan submittals, and that initial quantifications of the level of emission performance be provided on an overall (all states participating in a given multi-state plan) basis, rather than a state-level basis.

Projections of future CO₂ emissions

Recognizing that this rule has a very long implementation period, what type of documentation does EPA believe necessary for supporting states' projections of future CO₂ emissions? EPA should either provide guidance, or allow states to use that data most reasonably available to a state. Minnesota would recommend that EPA not require the use of IPM modeling for state-level emissions projections.

Procedure for review of initial plans

According to the preamble (70 FR 34915), if EPA determines that the initial plan does not meet the guidelines [identified in the rule language], EPA will notify the state by letter, within 60 days, that the agency cannot approve the state's initial plan as submitted. EPA believes this approach is authorized by, and consistent with, section 60.27(a) of the implementing regulations.

EPA's intent for the initial plan approval/disapproval process is unclear. Under 40 CFR 60.27(a), EPA may extend the period for submission of any plan or plan revision. Is EPA suggesting that the 60-day letter will serve as some sort of extension of the period for submission of the initial plan, or that it would serve as EPA's official proposal for disapproval, thereby triggering EPA's obligations to propose its own plan for a State (Section 60.27(c))? EPA's proposed rule language Section 60.5760(b) suggests that EPA's 60-day letter will find that the initial submittal does not meet the plan requirements, which would suggest EPA considers the letter as a disapproval. However, Section 60.27(b) indicates that EPA will propose a plan for approval or disapproval, suggesting a formal notice and comment period. Please clarify EPA's procedure for disapproved initial plan submittals, and indicate where States will be afforded the opportunity for formal notice and comment of such disapprovals, prior to EPA's promulgation of its own plan for a State.

Changes between initial and final plan submittal

Please provide additional detail regarding EPA's process approach for States whose initial strategies may change between initial and final plan submittal. For example, a failure of a Memorandum of Agreement for a multi-state plan results in a State choosing to withdraw and pursue a single-state plan after the single-state plan submittal deadline passes. Would EPA automatically consider the State to have failed to submit its plan, would it find the State deficient only after the multi-state deadline passed, or does EPA intend to provide some mechanism authorizing such a change in strategy in its final rulemaking? For a State that initially intended to submit a single-state plan but which, after June 30, 2016, chooses to instead participate in a multi-state approach, must they complete a formal revision of their initial plan submittal to indicate the revised approach?

Plan Review Procedures

Minnesota applauds the flexibility in choosing compliance strategies provided by EPA's proposal; however, the very same flexibility can potentially result in significant uncertainty, and even disparate treatment, for regulated entities, including states and affected facilities. Plan approvals and disapprovals will, presumably, occur at EPA regional office level. Without detailed central guidance and direction regarding approvable plan elements, similar compliance strategies could be viewed differently amongst different EPA regional offices. EPA must ensure consistent plan review across all regions in order to provide regulatory certainty to all stakeholders.

Additionally, please clarify the approval authority for multi-state plans that cross EPA regions. Though geographic proximity is not a requirement for a multi-state plan, it is likely that many, if not most, multi-state plans will include nearby states in similar ISO/RTO systems. Minnesota and the four states it borders are a part of MISO, yet cross three EPA regional office boundaries.

Stakeholder proposals – model trading rule

EPA invited comments on key stakeholder proposals, including the proposal that EPA should put forward a model rule for an interstate emissions credit trading program that could be adopted by states wanting to use such a program for its plan. Minnesota supports such a proposal, and recommends that EPA develop a model trading rule that states could incorporate by reference as a part of its plan, and automatically be included in a multi-state trading program. Such a program would likely minimize costs of compliance by allowing the most efficient reductions to CO₂ emissions to be selected for a region. If such a rule were developed by EPA, it should clarify whether states incorporating by reference would be considered subject to single or multi-state plan requirements.

Compliance periods/increments of emissions performance/ Reporting requirements/anti-backsliding

Section 60.5740(a)(3)(iii) of the proposed rule language indicates that for the interim plan performance period, state plans must identify the emission performance levels anticipated under the plan during "each year 2020 through 2029." Section 60.5775(c)(1) indicates that the state plan must include increments of emissions performance within the interim performance period for "every 2-rolling calendar years..." Please clarify whether EPA means for state plans to identify a yearly, or a rolling 2-year average performance level.

Minnesota does not necessarily object to the inclusion of annual or rolling two-year average performance levels in the state plans. The identification of such levels can be a useful tool in planning, and can help states and EPA to better manage compliance timelines when dealing with the long implementation deadline of the Clean Power Plan proposal. However, the long implementation period makes it difficult to produce precise and accurate annual performance projections – particularly when compliance with Clean Air Act requirements must also align with the complexities of energy planning. Annual (or rolling two-year) performance levels must be considered estimates for planning purposes only. The state reporting requirements identified in §60.5815 make the performance levels identified in state plans essentially binding, because states whose emission performance is greater than 10 percent in excess of projected plan

performance must specify/take corrective actions to be taken to ensure required interim plan performance. Minnesota believes such annual requirements to be unnecessarily onerous and unrealistic, particularly when dealing with such long-term implementation periods. If EPA means to establish some binding mid-course performance requirements (in addition to the interim targets it proposes), a more reasonable approach would be to require states to identify the average performance expected by, say 2025 (midway through the implementation period), and submit a mid-course review evaluating the state's performance up to that point and requiring corrective actions if needed.

Records retention

On page 34914 of the preamble, EPA states that it is "proposing that state plans must include a record retention requirement of ten years." Page 34855 of the proposal, however, contains proposed rule language, and states in section 60.5810(d) that "A state must keep records at minimum for 20 years." Please clarify.

Guidance/templates

EPA requests comment on whether to develop guidance for a number of topics: enforceability considerations related to requirements in a state plan for entities other than affected EGUs; evaluation, monitoring, and verification of renewable energy and demand-side energy efficiency programs and measures incorporated in state plan; tools and methods for projecting emission performance in state plans; and the inclusion of non-BSER emission reduction methods (such as electricity transmission efficiency improvements or the use of new NGCC units) in state plans.

Minnesota requests that EPA develop guidance for all topics identified. However, guidance must be timely, and made available for states as they begin to develop their state plans. EPA has often delayed guidance related to State Implementation Plan development to shortly before, or even after, the required submittal deadline, leaving States in a position of having to decide between developing and submitting plans that may be inconsistent with pending EPA guidance (and risk disapproval of said plans), or delaying plan development and submittal and risking a finding of failure to submit by EPA. EPA must ensure that its guidance – particularly guidance that will be necessary for states to develop federally approvable plans – is completed and made available to states early in the planning process.

Environmental Justice and Equity Considerations

The effects of climate change can be more pronounced on lower-income and urban residents. Higher summertime temperatures and extreme heat events may lead to increased illnesses, such as heat stroke, and worsening of respiratory disease, cardiovascular conditions, and other illnesses. Heat island effects can make such situations even worse in urban areas. Lower-income Minnesotans and the elderly, who often have less ability to get relief from extreme heat, can be at even greater risk. We applaud EPA's proposal, and its efforts to address the significant effects of climate change, and strongly encourage EPA to consider these effects on lower-income and urban residents as it develops a final rule. The final rule should consider and seek to limit additional burdens to lower-income communities and people of color, and require state plans to address such concerns.



Minnesota Pollution Control Agency

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September 16, 2014

U.S. Environmental Protection Agency
EPA Docket Center (EPA/DC)
Attention: Docket ID No. EPA-HQ-OAR-2013-0602
1200 Pennsylvania Avenue NW
Mail Code: 28221T
Washington, D.C. 20460

RE: Docket ID No. EPA-HQ-OAR-2013-0602

To Whom It May Concern:

The Minnesota Pollution Control Agency (MPCA) is pleased to submit the following comments on the U.S. Environmental Protection Agency's (EPA's) proposed "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," rule (also known as the "Clean Power Plan") published in the *Federal Register* on June 18, 2014.

The MPCA applauds the EPA's proposed rule approach, which closely matches Minnesota's policies and programs that have been in place over the last two decades and have reduced emissions of greenhouse gases from the electricity generating sector. The proposed rule addresses the critical need for carbon regulations to protect citizens, the environment and further development of a clean energy economy. Minnesota is proof that aggressive carbon emissions reductions from the power sector can be achieved while growing the economy, and we look forward to being a leader among states in addressing the requirements of the final Clean Power Plan.

Enclosed please find the MPCA's initial set of comments, focusing on important technical issues and data corrections for the proposed rule. The MPCA's initial comments address the following issues:

1. The MPCA requests certain corrections to electric generating unit operating status/characteristics used in calculating Minnesota's goals.
2. The MPCA requests clarification of the definition of affected units regarding the treatment of biomass-fired units.
3. The MPCA requests that EPA provide all states with the mass-based calculation of the state goal.
4. The MPCA requests that EPA issue a Notice of Data Availability prior to rule finalization that provides final targets and any necessary data corrections.

U.S. Environmental Protection Agency
Page Two
September 16, 2014

We plan to submit additional input on the proposal before the comment period closes. Because potential changes to technical data associated with Minnesota's affected units may influence additional comments on the Clean Power Plan proposal by the MPCA, we respectfully request an initial response to the enclosed comments as soon as possible.

The MPCA appreciates the opportunity to comment on EPA's proposed Clean Power Plan. If you have any questions regarding the enclosed comments, please contact David Thornton at 651-757-2018, or j.david.thornton@state.mn.us.

Sincerely,

A handwritten signature in black ink, appearing to read "John Linc Stine".

John Linc Stine
Commissioner

JLS/MK:vs

Enclosures

cc: David Thornton, MPCA
Frank Kohlasch, MPCA

Technical Comments/Corrections for Proposed Clean Power Plan, Docket ID No. EPA-HQ-OAR-2013-0602

1. The MPCA requests certain corrections to EGU operating status/characteristics used in calculating Minnesota's goals

Northern States Power Minnesota (Xcel Energy)—Sherburne County—Unit 3—ORIS 6090

This 938 MW (nameplate capacity) coal-fired electric generating unit was out of service during the entire calendar year 2012 due to an explosion in 2011 in the turbine as the unit was returning to service after an outage. The unit was off line for about 2 years while repairs were made, and did not return to full service until January 2014.

Minnesota will continue to rely on generation from this unit through the duration of the planning period for this rule and beyond. We believe that this unplanned outage makes the starting assumptions for coal-fired generation in Minnesota atypical, and requires that the baseline conditions for Minnesota be modified to include generation from this unit.

We believe that the average generation from 2009 to 2011, the three years prior to the explosion, is the best approximation of likely generation at Sherco Unit 3 in the year 2012, that is, 5,492,640 MWh releasing a total mass of 5,775,175 tons of CO₂, as calculated from the monthly data reported to the CAMD database for this unit. We believe that this three year average reasonably approximates the amount of coal generation that might have occurred at Sherco 3 in 2012; the selection of these years reflects generation during the recession (2009) as well as the increasing reliance on wind generation by Xcel to meet its renewable energy generation required by Minnesota statute. Since reaching full capacity in January 2014, the unit has operated at an average monthly load of 469,000 MWh, which represents an annual average generation of 5,630,000 MWh. The MPCA's recommendation thus is a slightly conservative but reasonable approximation of likely 2012 generation at Sherco 3.

The MPCA recognizes that the EPA would likely be interested in "balancing" the assignment of generation at Sherco 3 by eliminating generation elsewhere. It would not be correct to simply assume that Sherco 3 generation could be replaced by adjusting generation at other Minnesota coal plants, or to remove generation from combined cycle plants in an effort to "rebalance" generation. Xcel Energy responded to an inquiry from Minnesota's Department of Commerce, the state authority charged with reviewing electric utility rate requests:

"...Given the dynamic nature of generation systems and the need to make multiple purchase decisions instantaneously in order to respond to load variations, it is impossible to manually determine what energy source was deployed in place of an out-of-service plant..."

Xcel Energy Response to Department of Commerce Information Request No. 125, Docket No. E002/GR-12-961 (copy attached)

The MPCA has reviewed generation Xcel's EGUs that operated in Minnesota during this period to determine if the units operated at higher rates than otherwise might have occurred with Sherco 3 online. Data from CAMD is displayed below in two graphs: Xcel-owned generation during this period (Figure 1), and generation at the Sherco plant itself (Figure 2). There is no discernable trend overall from all Xcel units (coal and gas), nor at Units 1 and 2 at Sherco.

EPA may be faced with conducting modeling to address potential similar issues with EGUs in other states. As result, if the EPA believes that generation needs to be adjusted, the MPCA suggests that the EPA conduct an *ex post* modeling exercise using an electricity system dispatch simulation model to evaluate which generation resources would be pushed out of the dispatch order if Sherco 3 had run in 2012, and adjust all generation accordingly. Minnesota does not have the capability to conduct this type of modeling.

Regardless, Minnesota is requesting that the EPA modify its calculation of Minnesota's 2012 baseline conditions to include generation at Sherco 3.

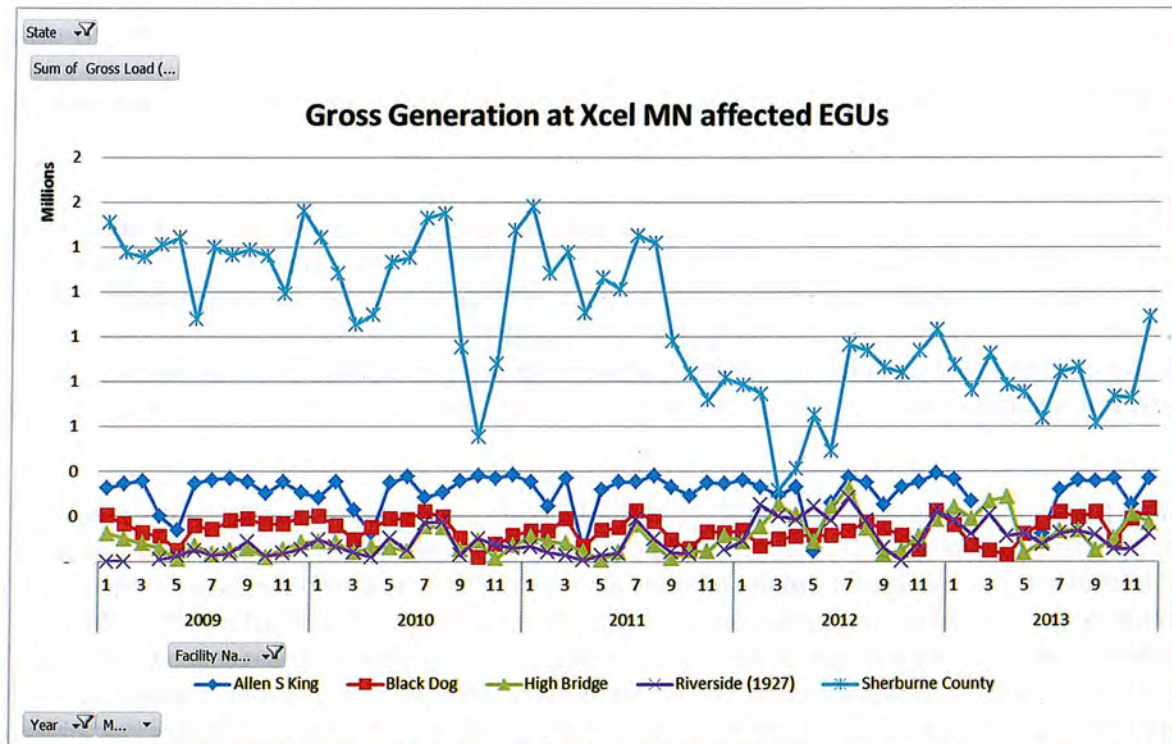


Figure 1. Generation at Xcel electric generating units located in Minnesota. Generation in 2012 at units other than Sherburne County operate at typical generation capacity during the outage of Sherco Unit 3.

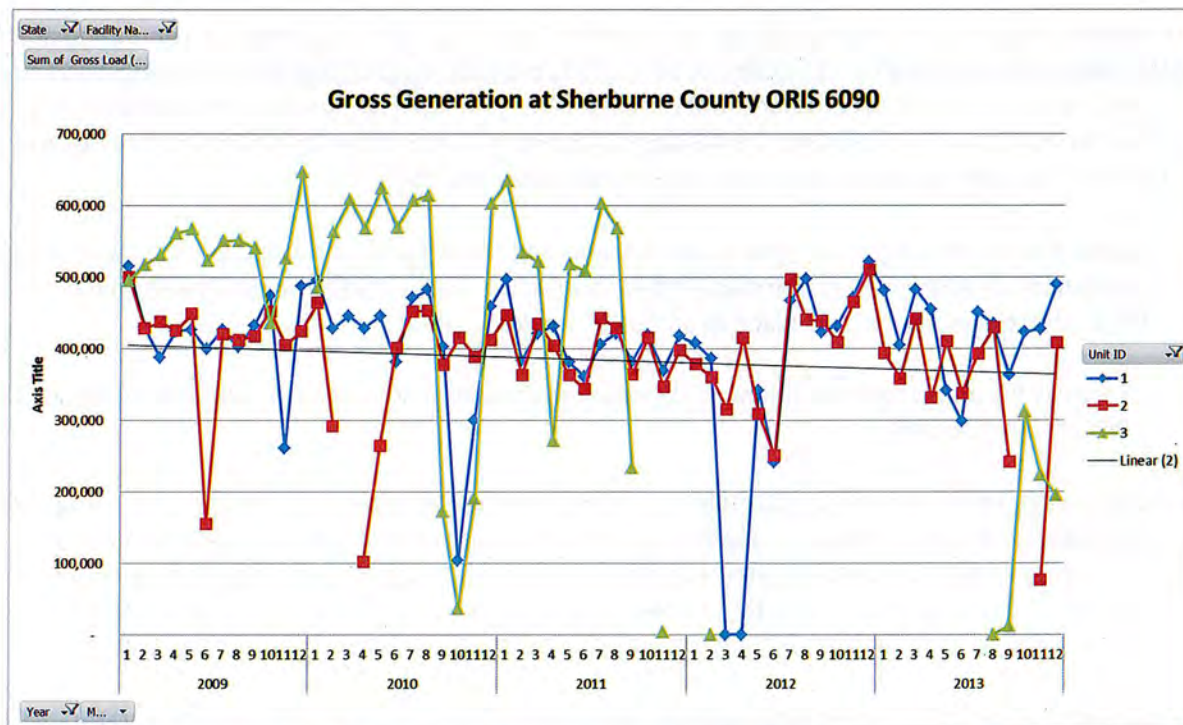


Figure 2. Generation at Sherburne County. Generation at Units 1 and 2 during the year were far below average during the first half of the year, then above average the second half.

Mankato Energy—ORIS 56104

Mankato Energy has a current capacity of a maximum of 375 MW at 6 degrees F. The nameplate capacity reported to EIA of 530 MW is due to the large capacity of the unit's steam turbine, if the facility had been constructed with all components. At this time, the steam turbine portion is oversized as the facility has only one combustion turbine and one heat recovery steam generator (HRSG).

The actual capacity of 375 MW is made up of 295 MW of combined cycle output with 80 MW of peaking power developed in the HRSG by employing duct burners. The existing Mankato Energy Center consists of one Siemens 501FD combustion turbine generator, one Nooter/Erikson HRSG, a Toshiba TCDF 40L steam turbine generator, and other ancillary equipment. In order to be able to generate up to 530 MW of power as the name plate capacity states, additional components must be installed at the unit. Because the plant was, and continues to be physically unable to generate 530 MW, the EPA should revise its presumption of the potential generation capacity for this unit to 375 MW.

Hutchinson Plant #2—ORIS 6358—Generators 2 and 3

In the EPA's preamble (79 FR 34892) the EPA states that state goals reflect the EPA's quantification of CO₂ from affected units. Hutchinson Plant #2 does not meet the criteria of an affected unit because its average annual operation has been below 219,000 MWh. These units have never operated at or above this threshold. These units should be removed from the EPA's list of affected sources. Accordingly, the NGCC capacity in MN should also be revised to remove this EGU.

2. The MPCA requests clarification of the definition of affected units regarding the treatment of biomass-fired units.

The EPA must also clarify the definition of affected units in two important ways. First, the EPA states in the preamble that it is its intent to adopt the rule "...that in all other respects would meet the applicability criteria for coverage under the proposed GHG standards for new fossil fuel-fired EGUs" (79 FR 1430; January 8, 2014)." 79 FR 34854 However, the proposed rule fails to include a provision similar to that included in the 111(b) new source rule exempting a steam generating unit combusting fossil fuel for less than 10% of its heat input during any 3 consecutive years.

Second, the EPA treats biomass units as carbon-neutral resources for goal-setting purposes, by including their MWh of generation in the denominator of the formula in Building Block 3, but including no CO₂ emissions in the numerator for these units. The MPCA is concerned however, that in compliance, the EPA implies that biomass would not be treated as a carbon-neutral resource, since it refers to the EPA's *Biomass Accounting Framework* for 111(d) plan development where the methodology describes adjusting top-of-stack biogenic CO₂ emissions based on the particular feedstock and location. The EPA acknowledges that in the review of the Framework, the Science Advisory Board indicated that biomass cannot be considered "...carbon neutral *a priori*, without an evaluation of the carbon cycle effects related to the use of the type of biomass being considered." 79 FR 1446.

As a result, it appears that states are, in effect, penalized in the goal setting formula for having biomass plants. Treating such plants as carbon neutral (i.e., not including those plants' CO₂ emissions) in the goal setting formula makes the goal more stringent, while treating as non-carbon neutral for goal compliance then discounts the use of biomass for goal achievement. Whether the EPA intends for biomass to be considered a carbon-neutral energy source or not, it should provide regulatory consistency in its treatment of biomass generation and not inadvertently penalize states with biomass generation.

The MPCA encourages the EPA to treat biomass units consistently in both target setting and target compliance calculations, and to ensure that final rule language includes applicability criteria referenced in the proposed rule preamble.

M L Hibbard--ORIS 1897-- Unit 3 and Unit 4

The MPCA believes that the biomass units at Minnesota Power's M L Hibbard station met the definition of affected units in 2012 and were mistakenly not included in Minnesota's affected units inventory. The MPCA believes that the EPA incorrectly excluded the Hibbard units from its evaluation of affected units because they burn wood as a "primary fuel." However, even if the EPA finalizes rule language (referenced above) providing an exemption for steam generating units combusting fossil fuel for less than 10% of their heat input during any three consecutive years, the units at Hibbard would not meet such an exemption, and should therefore be included in Minnesota's inventory of affected units and considered in Minnesota's goal calculation.

Minnesota Power's Hibbard plant Unit 3 at 35.3 MW and Unit 4 at 37.5 MW were constructed in 1949 and 1951 respectively as coal-fired power boilers. Minnesota Power re-commissioned the units, which are now burning wood and coal as cogeneration units, providing steam to the papermaker located adjacent to the Hibbard plant in Duluth, Minnesota and electricity to the grid.

The MPCA has evaluated the characteristics of this facility in order to determine if the EGUs become subject to the rule under the proposed definition of an affected unit. Each unit has a capacity to burn fossil fuel (coal and natural gas) at a steady state rate greater than 250 mmbtu/hr alone or in combination with wood, was constructed for the purpose of providing more than 1/3 of its electric output and more than 219,000 MWh to the utility distribution grid. In the baseline year 2012, coal provided approximately 28% of Unit 3's heat input, and 20% of Unit 4's heat input. Hibbard's title V permit does not contain federally enforceable limits to restrict the amount of fossil fuel the units are allowed to combust, nor the amount of electricity sold such that the units are not considered EGUs.

Even with a revised rule definition to allow up to 10% of fossil fuel for startup and combustion stabilization, the MPCA believes that fossil fuel emissions and generation for these units should be included in Minnesota's inventory of affected units, as they are burning fossil fuel in excess of the EPA's apparent intended exemption.

3. The MPCA requests that the EPA provide all states with the mass-based calculation of the state goal.

The EPA's proposal currently allows states the option to either adopt the EPA-provided rate-based form of the emissions goal, or to calculate a translation of the rate-based goal into a mass-based goal. If a state chooses to use a mass-based goal, its plan must demonstrate that its mass-based approach achieves the equivalent stringency to the rate-based goal set by the EPA. The state-by-state calculation of a rate-based approach to a mass-based approach presents unnecessary complication and inconsistency state goal-setting, and results in regulatory uncertainty on the part of states and affected utilities, who must await EPA approval to determine whether their goal calculation is sufficient. The EPA could avoid such difficulties by providing each state with the mass-based emissions goal, providing the states with the substantive opportunity to provide comments and corrections on the mass-based goals, as they have with the rate-based goals.

4. The MPCA requests that the EPA issue a Notice of Data Availability prior to rule finalization that provides final targets and any necessary data corrections.

The MPCA expects the EPA to make technical corrections and modifications to the proposed rule based, in part, on public comments received. The EPA may also make more fundamental changes to the building block methodologies as a result of public comments. Because such changes may result in modified goals for states, the EPA should issue a Notice of Data Availability (or multiple notices, as needed), providing states the opportunity to review and provide comment on the changes to the state rate and mass goals, prior to rule finalization. The EPA used a similar approach with the Cross-State Air Pollution Rule, which helped states in their compliance planning and provided additional quality-assurance to the rule's technical elements.

Docket No. E002/GR-12-961
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Xcel Energy

Docket No.: E002/GR-12-961

Response To: Department of Commerce Information Request No. 125

Requestor: Dale Lusti, Nancy Campbell & Angela Byrne

Date Received: December 6, 2012

Question:

Subject: Sherco 3 Outage

Reference: Direct Testimony of Kent T. Larson

On Pages 29 to 31 identified above, Mr. Larson discusses the Sherco 3 outage.

- A. Please identify all insurance proceeds and litigation proceeds that have been received to date and the status of future anticipated proceeds with regard to the Sherco 3 plant damage and related plant outage.
- B. Please address for all proceeds provided in (A) above, whether or not proceeds were included in the rate case and if so where, or if proceeds were not included, why that omission is appropriate.
- C. Has Xcel Energy experienced increased replacement power costs as a result of the Sherco 3 outage?
- D. If the response to (C) above is yes:
- (1) Has Xcel Energy passed the increased replacement power costs on to its ratepayers? If so, please quantify these costs showing all calculations.
- (2) Please explain how Xcel Energy has passed the increased replacement power costs on to its ratepayers.
- (3) Please identify the amount of insurance and litigation proceeds that ratepayers have received (to date) to offset increased replacement power costs with regard to the Sherco 3 outage.
- (4) Please identify the total amount of insurance and litigation proceeds ratepayers should expect to receive prior to the beginning of the test-year

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(January 1, 2013) to offset increased replacement power costs with regard to the Sherco 3 outage.

(5) Please identify the total amount of insurance and litigation proceeds ratepayers should expect to receive during the test-year (beginning January 1, 2013) to offset increased replacement power costs with regard to the Sherco 3 outage.

- E. Please identify all insurance and litigation proceeds that have been included as an offset to the test-year revenue requirements, to reflect the increased replacement power costs as a result of the Sherco 3 outage.

Response:

- A. There has been no litigation related to the Sherco 3 plant damage, and therefore no litigation proceeds have been received to date. The Company has not yet determined whether or not litigation is appropriate but would not, in any event, expect to pursue litigation claims until after the project has been completed and the final costs have been determined. We have received [TRADE SECRET BEGINS... ...TRADE SECRET ENDS] in insurance payments so far and expect to receive an additional [TRADE SECRET BEGINS... ...TRADE SECRET ENDS] by the end of 2012. These insurance payments are net of the [TRADE SECRET BEGINS... ...TRADE SECRET ENDS] deductible and have covered labor and equipment expenses associated with the repairs at Sherco 3.
- B. The insurance reimbursements have not been included in the rate case. The Company submits to our insurance providers the work orders, purchase orders and invoices for labor and equipment expenses associated with the repairs at Sherco 3. The Company's insurers then review this material and indemnify the Company for those expenses covered by the master operational property insurance policy.
- C. Yes, according to simulation analysis from our computer model discussed in the Company's Sherco 3 update report to the Minnesota Public Utilities Commission on November 7, 2012 in Docket No. E002/M-11-1173, we estimate there have been some increased replacement energy costs relative to the Locational Marginal Prices (LMPs) from MISO Day 2 energy market as a result of the Sherco 3 outage.

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- D(1). Yes, as with all applicable monthly system fuel and purchased energy costs, the actual embedded replacement energy costs are passed on to ratepayers through the fuel clause mechanism. Given the dynamic nature of generation systems and the need to make multiple purchase decisions instantaneously in order to respond to load variations, it is impossible to manually determine what energy source was deployed in place of an out-of-service plant. Attachment A to this response details our best estimate of quantifying increased replacement energy costs for the period of November 19, 2011 to October 31, 2012. The approach we employed is as follows:

$$\text{Average Replacement Cost} - \text{Unit Incremental Cost} = \text{Cost Change due to Outage}$$

Since our Fuel Clause mechanism is based on accounting records, our actual Sherco Unit 3 outage replacement costs may be different from the simulated results illustrated on Attachment A. In addition, the Unit Incremental Cost is an estimate of the cost of energy from Sherco 3 using assumed coal prices and other incremental costs, and assumed production levels. In some periods, the MISO LMP price was less than the estimated Sherco 3 production cost due to very low natural gas prices and MISO LMP prices. In those hours, the Sherco 3 outage reduced energy costs to our ratepayers.

Please note that Attachment A is marked "Non-Public," as it contains information we consider to be trade secret data as defined by Minn. Stat. §13.37(1)(b). The information derives an independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use. Based on its economic value, the Company maintains this information as trade secret as well as the insurance payment and deductible amounts noted in Part A of this response.

- D(2). Please see D(1) above.
- D(3). Though we have received insurance payments, these payments have been used to pay for actual parts and labor costs at the plant. As is common in the electric utility industry, our current insurance policy does not provide coverage for replacement power costs. Therefore, the Company and ratepayers have not, and will not, receive any insurance proceeds to cover replacement power costs. As noted above, any litigation proceeds are unknown at this time.
- D(4). Please see D(3) above.

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D(5). Please see D(3) above.

E. Please see D(3) above.

Witness: Kent T. Larson
Preparer: Bob Miller / Anne Heuer
Kerry Koep / John Chow
Title: Manager, Hazard Insurance / Manager, Revenue Analysis
Managing Attorney / Pricing Consultant
Department: Hazard Insurance / Revenue Requirements North
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Date: December 21, 2012

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Northern States Power Company

Docket No. E002/GR-12-961

Information Request DOC-125

Attachment Page 1 of 1

Estimation of Sherco Unit 3 Outage Replacement Energy Costs
November 2011 - October 2012

Period	Total Outage MWH	Average Replacement Cost	Unit Incremental Cost	Change in Energy Costs Due to Outages
November 2011*	<i>[Trade Secret Begins]</i>	\$1,951,782	<i>[Trade Secret Begins]</i>	<i>[Trade Secret Begins]</i>
December 2011		\$7,701,441		
January 2012		\$6,299,086		
February 2012		\$6,067,854		
March 2012		\$5,705,721		
April 2012		\$6,140,351		
May 2012		\$9,281,594		
June 2012		\$9,160,688		
July 2012		\$13,199,676		
August 2012		\$8,767,767		
September 2012		\$4,860,041		
October 2012		\$5,327,359		
	<i>Trade Secret Ends]</i>		<i>Trade Secret Ends]</i>	<i>Trade Secret Ends]</i>
Period Total	3,420,847	\$84,463,360	\$61,747,321	\$22,716,039

* Period from November 19, 2011 to November 30, 2011.

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Xcel Energy

Docket No.: E002/GR-12-961

Response To: Department of Commerce Information Request No. 193

Requestor: Nancy Campbell, Dale Lusti & Angela Byrne

Date Received: January 8, 2013

Question:

Subject: Sherco 3 Costs

Reference: Larson Direct Testimony on page 15 and other applicable Testimony

- A. Please identify all costs of Sherco 3 including but not limited to, depreciation expense, taxes, insurance, O&M, emission chemicals, return on rate base, etc. for 2009 test year, 2009 actual, 2010 actual, 2011 test year, 2011 actual, 2012 actual, 2013 test year.
- B. For 2013 test year, did the Company include all costs of Sherco 3, even though this unit is not expected to be operational in the first quarter of 2013? If yes, please explain why this is appropriate in light of the Company's statement that it will be filing a rate case for 2014?
- C. Please provide information to support that Sherco 3 will be back in service at the "end of the first quarter of 2013" as stated on page 30 of Mr. Larson's Direct Testimony. Please include percentage of completion of projects related to Sherco 3.

Response:

- A. Please see Attachment A for costs associated with Sherco 3 for 2009 test year, 2009 actual, 2010 actual, 2011 test year, 2011 actual, 2012 actual, 2013 test year.
- B. Yes. As indicated in the response to part A, the 2013 test year includes costs for Sherco 3. The Company began initial development of the 2013 budget in early 2012, and the budget was completed by August 2012. For planning purposes, the 2013 budget assumed a January 1, 2013 return to service for Sherco 3. By the time of filing of this case, the Company determined that the Sherco 3 restoration project would take additional time and was expected to return to service at the end of the first quarter of 2013.



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November 5, 2014

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Report In the Matter of the Integration and Transmission Study for the Future Renewable Energy Standard Required by Minnesota Laws 2013, Chapter 85, Article 12, Section 4, Directed by the Minnesota Department of Commerce-Division of Energy Resources**
Docket No. E999/CI-13-486

Dear Dr. Haar:

The Minnesota Department of Commerce-Division of Energy Resources (Department) provides the attached Report, as required by Minnesota Laws 2013, Chapter 85, Article 12, Section 4 (the Act).

Other than accepting the report, the Minnesota Public Utilities Commission (Commission) is not required to take action. However, the Commission may find the information to be helpful in various decisions that may come before the Commission. The Department and the Study Team who developed the report would be willing to present the material in the report at a Commission Planning Meeting, if that would be helpful. In addition, the Department notes that there will be a webinar on the report on Thursday, November 6, 2014, beginning at 1:30 as discussed further herein.

The Department's consultant, Matt Schuerger, is available to answer any questions the Commission may have on the report.

Sincerely,

A handwritten signature in black ink, appearing to read "W. Grant".

/s/ WILLIAM GRANT
Deputy Commissioner

WG/ja
Attachment

I. BACKGROUND

Article 12, section 4 of Minnesota Laws 2013, Chapter 85 required the Minnesota Public Utilities Commission (Commission) to order all electric utilities and transmission companies to conduct an engineering study regarding the effects on the reliability and cost of increasing Minnesota's renewable energy standard (RES) to at least 40 percent by 2030, as follows:

INTEGRATION AND TRANSMISSION STUDY FOR FUTURE RENEWABLE ENERGY STANDARD.

(a) The commission shall order all Minnesota electric utilities, as defined in Minnesota Statutes, section 216B.1691, subdivision 1, paragraph (b), and all transmission companies, as defined in Minnesota Statutes, section 216B.02, to conduct an engineering study of the impacts on reliability and costs of, and to study and develop plans for the transmission network enhancements necessary to support, increasing the renewable energy standard established in Minnesota Statutes, section 216B.1691, subdivision 2a, to 40 percent by 2030, and to higher proportions thereafter, while maintaining system reliability.

(b) The Minnesota electric utilities and transmission companies must complete the study work under the direction of the commissioner of commerce. Prior to the start of the study, the commissioner, in consultation with Minnesota electric utilities and transmission companies, shall appoint a technical review committee consisting of up to 15 individuals with experience and expertise in electric transmission system engineering, electric power systems operations, and renewable energy generation technology to review the study's proposed methods and assumptions, ongoing work, and preliminary results.

(c) As part of the planning process, the Minnesota electric utilities and transmission companies must incorporate and build upon the analyses that have previously been done or that are in progress including but not limited to the 2006 Minnesota Wind Integration Study and ongoing work to address geographically dispersed development plans, the 2007 Minnesota Transmission for Renewable Energy Standard Study, the 2008 and 2009 Statewide Studies of Dispersed Renewable Generation, the 2009 Minnesota RES Update, Corridor, and Capacity Validation Studies, the 2010 Regional Generation Outlet Study, the 2011 Multi Value Project Portfolio Study, and recent and ongoing Midcontinent Independent System Operator transmission expansion planning work. The utilities and transmission companies shall collaborate with the Midcontinent Independent System Operator to optimize and integrate, to the extent possible, Minnesota's transmission plans with other

regional considerations and to encourage the Midcontinent Independent System Operator to incorporate Minnesota's planning work into its transmission expansion future planning.

(d) The study must be completed and submitted to the Minnesota Public Utilities Commission by November 1, 2014. The report shall include a description of the analyses that have been conducted and the results, including:

(1) a conceptual plan for transmission necessary for generation interconnection and delivery and for access to regional geographic diversity and regional supply and demand side flexibility; and

(2) identification and development of potential solutions to any critical issues encountered to support increasing the renewable energy standard to 40 percent by 2030, and to higher proportions thereafter, while maintaining system reliability.

This report, called the “Minnesota Renewable Energy Integration and Transmission Study” (MRITS), is intended to fulfill this requirement. The Minnesota Department of Commerce (Department) requests that the Commission accept the report.

II. SUMMARY OF REPORT

The Minnesota utilities and transmission companies, in coordination with the Midcontinent Independent System Operator (MISO), conducted the engineering study. The Department directed the study, conducted by a preeminent technical study team of highly skilled local, regional, and national engineering organizations. The utilities’ most experienced planning and operations engineers worked hard and constructively throughout the year to accomplish, in collaboration with MISO, a successful and timely completion of the study.¹ In addition to key personnel from Minnesota’s utilities, the team included Excel Engineering Inc. (power flow analysis, conceptual transmission plan), MISO (production simulation analysis), and GE Energy Consulting (operational performance analysis, dynamics analysis, mitigations and solutions, study report).

The Department greatly appreciates all of the work by the technical review team and particularly appreciates Great River Energy’s (GRE) early and ongoing leadership with the study.

The following are the key findings of the MRITS report:

- The addition of wind and solar (variable renewable) generation to supply 40 percent of Minnesota’s annual electric retail sales can be reliably accommodated by the electric power system.

¹ The Department acknowledges that the report is being filed subsequent to the November 1, 2014 due date. The extra days were needed to allow for final review and incorporation of edits.

- With upgrades to existing transmission, the power system can be successfully operated for all hours of the year (no unserved load, no reserve violations, and minimal curtailment of renewable energy) with wind and solar resources increased to achieve 40 percent renewable energy in Minnesota and with current renewable energy standards fully implemented in neighboring MISO North/Central states.
- Further analysis would be needed to ensure system reliability at 50 percent of Minnesota's annual electric retail sales from variable renewables.
- With wind and solar resources increased to achieve 50 percent renewable energy in Minnesota and 25 percent renewable energy in MISO North / Central (10 percent above current renewable energy standards in neighboring states), MRITS production simulation results show that, with significant transmission upgrades and expansions in the five state area, the power system can be successfully operated for all hours of the year (no unserved load, no reserve violations, and minimal curtailment of renewable energy).
- Due to study schedule limitations, no dynamic analysis was performed for 50 percent renewable energy in Minnesota; such analysis would be necessary to ensure system reliability.

III. RECOMMENDED NEXT STEPS

This MRITS report does not requires action by the Commission. However, the report may provide helpful information in proceedings that may come before the Commission. The Department and the Study Team who developed the report would be willing to present the material in the report at a Commission Planning Meeting, if that would be helpful.

In addition, there will be a webinar on the report on Thursday, November 6, 2014, beginning at 1:30. Registration is at: <https://www1.gotomeeting.com/register/314429457>

/ja



GE Energy Consulting

Minnesota Renewable Energy Integration and Transmission Study

Final Report

Prepared for:

- The Minnesota Utilities and Transmission Companies
- The Minnesota Department of Commerce

Prepared by:

- GE Energy Consulting, *with contributions by:*
 - The Minnesota Utilities and Transmission Companies
 - Excel Engineering, Inc.
 - MISO

In Collaboration with MISO

October 31, 2014

Legal Notices

This report was prepared by General Electric International, Inc. (GE) as an account of work sponsored by Great River Energy which was serving as a representative of the Minnesota Utilities and Transmission Companies. Neither Great River Energy nor GE, nor any person acting on behalf of either:

1. Makes any warranty or representation, expressed or implied, with respect to the use of any information contained in this report, or that the use of any information, apparatus, method, or process disclosed in the report may not infringe privately owned rights.
2. Assumes any liabilities with respect to the use of or for damage resulting from the use of any information, apparatus, method, or process disclosed in this report.

October 31, 2014

In 2013 the Minnesota Legislature adopted a requirement for a Renewable Energy Integration and Transmission Study¹ (MRITS). MRITS is an engineering study of increasing the Minnesota Renewable Energy Standard to 40% by 2030, and to higher proportions thereafter, while maintaining system reliability.

Background. MRITS builds upon prior renewable integration studies and related technical work and is coordinated with recent and current regional power system study work. Over summer 2013, Commerce reviewed prior and current related studies and worked with stakeholders and study participants to identify key issues. In fall 2013, Commerce held a stakeholder meeting to discuss the objectives, scope, schedule, and process. The study began in November 2013 and was completed in October 2014.

Study details. *MRITS is focused on the reliability impacts of increased levels of variable renewables (wind and solar generation) and the associated costs of those impacts.* The study scope was developed from statutory guidance, stakeholder input, and technical study team refinement. MRITS incorporates three core and interrelated analyses: 1) *Power flow analysis* for development of a conceptual transmission plan, which includes transmission necessary for generation interconnection and delivery and for access to regional geographic diversity and system flexibility; 2) *Production simulation analysis* which evaluates hour-by-hour operational performance for an entire year, including reserve violations, unserved load, wind / solar curtailments, thermal cycling, and ramp rate and ramp range, and, to screen for challenging time periods; and 3) *Dynamics analysis*, which includes transient stability analysis and weak system strength analysis. The broad study scope and the aggressive schedule have been very significant challenges.

Technical team. *The MN utilities and transmission companies, in coordination with MISO, conducted the engineering study.* The Department of Commerce directed the study. The Minnesota utilities and transmission companies engaged early in the study development and, through the active participation of the companies' most experienced planning and operations engineers, worked hard and constructively throughout the year to accomplish, in collaboration with MISO, a successful and timely completion of the study. A preeminent technical study team of highly skilled local, regional, and national engineering organizations was assembled to work collaboratively on the analysis. This included major contributions from the Minnesota utilities and transmission companies (siting, conceptual transmission plan), Excel Engineering Inc (power flow analysis, conceptual transmission plan), MISO (production simulation analysis), and GE

¹ MN Laws 2013, Chapter 85 HF 729, Article 12, Section 4; MPUC Docket No. CI-13-486.

Energy Consulting (operational performance analysis, dynamics analysis, mitigations and solutions, study report). Great River Energy (GRE) provided key early and ongoing study leadership. GRE's Gordon Pietsch organized and coordinated full participation by the Minnesota utilities and transmission companies and GRE's Jared Alholinna led the technical study team – both worked tirelessly and effectively to ensure the best, most knowledgeable, most experienced engineers were organized, funded, focused, and coordinated throughout the study.

Study review. The study has greatly benefited from extensive ongoing review and guidance by an expert Technical Review Committee (TRC). The Department of Commerce appointed and led the TRC, which included engineers with experience and expertise in electric transmission system engineering, electric power system operations, and renewable energy generation technology. Seven TRC meetings, four full day and three half day, were held throughout the course of the study to review and discuss the study methods and assumptions, scenarios, model development, results, and key findings. *With excellent input from the utilities and transmission companies, MISO, renewables specialists, and national experts, consensus was reached on overall study methods and assumptions, on the scenarios to be studied, on the modeling approach, and on the results and key findings.*

Key findings. *The analytical results from this study show that the addition of wind and solar (variable renewable) generation to supply 40% of Minnesota's annual electric retail sales can be reliably accommodated by the electric power system. The MRITS operational and dynamics analyses results show that, with upgrades to existing transmission, the power system can be successfully operated for all hours of the year (no unserved load, no reserve violations, and minimal curtailment of renewable energy) with wind and solar resources increased to achieve 40% renewable energy in Minnesota and with current renewable energy standards fully implemented in neighboring MISO North/Central states. Further analysis would be needed to ensure system reliability at 50% of Minnesota's annual electric retail sales from variable renewables. With wind and solar resources increased to achieve 50% renewable energy in Minnesota and 25% renewable energy in MISO North / Central (10% above current renewable energy standards in neighboring states), MRITS production simulation results show that, with significant transmission upgrades and expansions in the five state area, the power system can be successfully operated for all hours of the year (no unserved load, no reserve violations, and minimal curtailment of renewable energy). Due to study schedule limitations, no dynamic analysis was performed for 50% renewable energy in Minnesota (Scenarios 2 and 2a) and this analysis is necessary to ensure system reliability.*

Thank you to all of the study participants for an extraordinary and collaborative effort and for successful completion of a ground breaking study.

Sincerely,



William Grant
Deputy Commissioner, Division of Energy Resources

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Nomenclature

BAU	Business as Usual
CC or CCGT	Combined Cycle Gas Turbine
CEMS	Continuous Emissions Monitoring Systems
CF	Capacity Factor
CO ₂	Carbon Dioxide
CSCR	Composite Short-Circuit Ratio
CV	Capacity Value
DA	Day-Ahead
DIR	Dispatchable Intermittent Resource
DPV	Distributed Photovoltaic Generation Resource
DR	Demand Response
DSM	Demand Side Management
EI	Eastern Interconnection
EMTP	Electro-Magnetic Transients Program
ERGIS	Eastern Renewable Generation Integration Study (by NREL)
EWITS	Eastern Wind Integration and Transmission Study (by NREL)
FERC	Federal Energy Regulatory Commission
GE	General Electric International, Inc. / GE Energy Consulting
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
HA	Hour Ahead
HVDC	High-Voltage Direct-Current
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LBA	Local Balancing Authority
LMP	Locational Marginal Prices
MRITS	Minnesota Renewable Energy Integration and Transmission Study
MTEP	MISO Transmission Expansion Plan
MVA	Megavolt Ampere
MVP	Multi-Value Project
MW	Megawatts
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation

Nomenclature

NOx	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
NS	Non-Synchronous
O&M	Operation & Maintenance
PJM	PJM Interconnection, LLC.
POI	Point of Interconnection
PPA	Power Purchase Agreement
PSCAD	Manitoba HVDC Research Centre's Electro-Magnetic Transients Simulation program (Power System Computer Aided Design)
PSH	Pumped Storage Hydro
PV	Photovoltaic
RE	Renewable Energy
REC	Renewable Energy Credit
RES	Renewable Energy Standard
RGOS	Regional Generation Outlet Study
RPS	Renewable Portfolio Standard
SCED	Security Constrained Economic Dispatch
SCR	Short-Circuit Ratio
SCUC	Security Constrained Unit Commitment
SES	Solar Energy Standard
SOx	Sulfur Oxides
ST	Steam Turbine
STATCOM	Static Compensator
SVC	Static Var Compensator
TPL	NERC's Transmission Planning Standard
TRC	Technical Review Committee
TWh	Terawatt Hour (1000 Megawatt hours)
VOC	Variable Operating Cost
WTG	Wind Turbine-Generator
ZVRT	Zero-Voltage Ride-Through

1 EXECUTIVE SUMMARY

1.1 Background

In 2013 the Minnesota Legislature adopted a requirement for a Renewable Energy Integration and Transmission Study¹ (MRITS). The MN utilities and transmission companies, in coordination with MISO, conducted the engineering study. The Department of Commerce directed the study and appointed and led the Technical Review Committee (TRC). It is an engineering study of increasing the Minnesota Renewable Energy Standard to 40% by 2030, and to higher proportions thereafter, while maintaining system reliability. The final study includes: 1) A conceptual plan for transmission for generation interconnection and delivery and for access to regional geographic diversity and regional supply and demand side flexibility, and 2) Identification and development of potential solutions to any critical issues encountered.

All utilities with Minnesota retail electric sales and all Minnesota transmission companies participated and/or were represented in the study. Eight Minnesota Local Balancing Authorities are represented and over 85% of the Minnesota retail sales are in the four largest Local Balancing Authorities (LBA): Xcel Energy (NSP), Great River Energy, Minnesota Power, and Otter Tail Power. The study area is within the NERC reliability region Midwest Reliability Organization (MRO). Nearly all of the Minnesota retail sales are within the Midcontinent Independent System Operator (MISO). The Local Balancing Authorities within MISO, including the Minnesota LBAs, are functionally consolidated.

Prior studies of relevance include the 2006 Minnesota Wind Integration Study², the 2007 Minnesota Transmission for Renewable Energy Standard Study³, the 2009 Minnesota RES Update, Corridor, and Capacity Validation Studies, the 2008 and 2009 Statewide Studies of Dispersed Renewable Generation⁴, the 2010 Regional Generation Outlet Study, the 2011 Multi Value Project Portfolio Study, the 2013 Minnesota Biennial Transmission Project Report⁵, the 2013 MISO Transmission Expansion Plan, and recent and ongoing MISO transmission expansion planning work⁶.

¹ MN Laws 2013, Chapter 85 HF 729, Article 12, Section 4; MPUC Docket No. CI-13-486.

² 2006 MN Wind Integration Study. Prepared for the MPUC, Nov 2006.

Final Report Volumes I & II, Final Report Presentation. <http://www.puc.state.mn.us/PUC/electricity/013752>

³ “Minnesota RES Update Study Technical Report.” March 2009. “RES Transmission Report.” November 2007.

“Southwest Twin Cities – Granite Falls Transmission Upgrade Study Technical Report.” March 2009.

“Capacity Validation Study Report.” March 2009. <http://www.minnelectrans.com/reports.html>

⁴ Dispersed Renewable Generation Studies. June 2008 and September 2009.

<http://mn.gov/commerce/energy/topics/resources/Reports-Data/Energy-Reports.jsp>

⁵ <http://www.minnelectrans.com/>, November 1, 2013.

⁶ <https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx>

1.2 Study Objectives and Overall Approach

The study objectives are listed below.

1. Evaluate the impacts on reliability and costs associated with increasing Renewable Energy to 40% of Minnesota retail electric energy sales by 2030, and to higher proportions thereafter;
2. Develop a conceptual plan for transmission necessary for access to regional geographic diversity and regional system flexibility;
3. Identify and develop options to manage the impacts of the renewable energy resources;
4. Build upon prior wind integration studies and related technical work; Coordinate with recent and current regional power system study work;
5. Produce meaningful, broadly supported results through a technically rigorous, inclusive study process.

This study is focused on the reliability impacts of increased levels of variable renewables (wind and solar generation) and the associated costs of those impacts.

MRITS builds upon prior wind integration studies and related technical work and is coordinated with recent and current regional power system study work. The study scope was developed from statutory guidance, stakeholder input, and technical study team refinement.

MRITS incorporates three core and interrelated analyses: 1) *Power flow analysis* for development of a conceptual transmission plan, which includes transmission necessary for generation interconnection and delivery and for access to regional geographic diversity and regional supply and demand side flexibility; 2) *Production simulation analysis* for evaluation of operational performance, including reserve violations, unserved load, wind / solar curtailments, thermal cycling, and ramp rate and ramp range, and, to screen for challenging time periods; and 3) *Dynamics analysis*, which includes transient stability analysis and weak system strength analysis.

The MRITS study area is Minnesota-centric, which focuses on the combined operating areas of the Minnesota utilities and transmission companies, in the context of the MISO North/Central areas and the neighboring regions to the west and north.

The base study models (baseline and scenarios) are coordinated with and consistent with MISO models and databases including dispatch to the MISO market. Additional options were considered in Task 7 (Identify & Develop Mitigations / Solutions) as needed.

The key study tasks are:

- Develop Study Scenarios; Site Wind and Solar Generation (Lead contributors: Minnesota Utilities; Minnesota Department of Commerce)
- Perform Production Simulation Analysis (Lead Contributor: MISO)
- Perform Power Flow Analysis; Develop Transmission Conceptual Plan (Lead Contributors: Minnesota Utilities & Transmission Owners; Excel Engineering)
- Evaluate Operational Performance (Lead Contributor: GE Energy Consulting)

- Screen for Challenging Periods (Lead Contributor: GE Energy Consulting)
- Evaluate stability related issues, including transient stability performance, voltage regulation performance, adequacy of dynamic reactive support, and weak system strength issues (Lead Contributor: GE Energy Consulting)
- Identify and Develop Mitigations and Solutions (Lead Contributor: GE Energy Consulting)

1.3 Development of Study Scenarios

The Baseline scenario has sufficient renewable energy generation to satisfy the current renewable energy standards and solar energy standards for all states in the study region. For Minnesota, the Baseline scenario was based on current Minnesota utility plans to meet the Minnesota Renewable Energy Standard (RES) and the Solar Energy Standard (SES) with renewable energy (wind, solar, small hydro, biomass, etc) from the Minnesota-centric area and incorporates refinements from the technical study team. For non-Minnesota MISO states in the study footprint, the Baseline scenario was based on the prior approved 2013 MISO Transmission Expansion Plan (MTEP13).

Scenario 1 builds on the Baseline scenario by adding incremental wind and solar (variable renewables) generation to the Baseline model to supply a total of 40% of Minnesota annual electric retail sales from renewables in the study year and with all states at full implementation of their current RESs.

Scenario 2 builds on Scenario 1 by adding incremental wind and solar generation to the Scenario 1 model to supply 50% of Minnesota electric retail sales from total renewables and by further adding incremental wind and solar generation to supply an additional 10% of the non-Minnesota MISO North / Central retail electric sales from total renewables (i.e. to increase the MISO footprint renewables 10% above full implementation of the current RESs).

Table 1-1 Study Scenarios

Scenario	Minnesota RE Penetration	MISO Wind & Solar Penetration (including Minnesota)
Baseline	28.5%	14.0%
Scenario 1	40.0%	15.0%
Scenario 2	50.0%	25.0%

Note: MISO has an additional 3% renewable energy penetration in all scenarios from existing small biomass and small hydro.

The horizon year for this study was 2028 (to represent 2030 conditions). System load levels for Minnesota and MISO regions were scaled up from present levels by an assumed annual growth rate of 0.5% for Minnesota and 0.75% for the rest of MISO North / Central.

All scenarios, including the Baseline, required more wind and solar generation than what is already installed on the grid. Therefore, the study team used a combination of wind/solar resource maps and wind/solar profile data (from NREL) to guide selection of sites for prospective future wind and solar plants with cumulative capacities consistent with the renewable energy targets for each study scenario. Wind Plant sites were distributed among several of MISO's renewable energy zones

(originally developed in the MISO Regional Generation Outlet Study and used in the Multi-Value Project Portfolio study).

1.4 Development of Transmission Conceptual Plans

A conceptual transmission plan was developed for each of the study scenarios. System reliability was determined through traditional transmission planning methods, criteria, and assumptions. Steady state performance characteristics were evaluated with the system intact as well as under powerflow contingency conditions (N-1 outages and selected multiple contingency outages per NERC TPL Category C2 & C5).

The Baseline scenario started with a transmission model that was consistent with the 2013 MTEP 2023 model. This Baseline transmission model incorporates planned transmission lines, including the CapX2020 Group I lines and the MISO Multi-Value Project (MVP) portfolio. A very limited number of facilities were overloaded in the Baseline Scenario.

For Scenario 1, a total of 54 transmission mitigations were added to accommodate the increased wind and solar generation. These mitigations included transmission line upgrades, transformer additions/replacements, and changes to substation terminal equipment, with a total estimated cost of \$373M. No new transmission lines were required.

In Scenario 2, a total of 17,245 MW of new wind/solar generation was added to increase Minnesota renewable energy penetration to 50% and MISO renewable energy penetration to 25%. A total of 9 new transmission lines and 30 transmission upgrades were added to the Scenario 1 transmission system, with a total estimate cost of an additional \$2.6B. Note that an undetermined portion of the Scenario 2 transmission expansions and upgrades are associated with increasing MISO's renewable penetration from 15% to 25%.

Note that for the development of transmission conceptual plans, the new wind and solar resources were connected to high voltage transmission buses. The actual connection processes will likely require additional plant-specific interconnection facilities for the new wind and solar plants.

1.5 Evaluation of Operational Performance

Operational performance of the electric power grid with increased levels of renewable generation was analyzed using production simulation analysis, which simulates hourly operation of the system for an entire year. The PLEXOS simulation tool uses a Day-Ahead Security Constrained Unit Commitment (SCUC) and Real-Time Security Constrained Economic Dispatch (SCED) interleaved market dispatch solution. This type of modeling accurately captures the forecast uncertainties realized between a Day-Ahead and Real-Time markets. Modeling of forecast uncertainty becomes increasingly important when dealing with high levels of wind and solar generation because the output tends to be more stochastic in nature.

MISO used the 2013 MTEP Business as Usual (BAU) dataset as a starting point for the Baseline Scenario, with modifications to the system load level to reflect the 2028 horizon year for this study. The BAU future is considered the status quo future and continues current economic trends. The MTEP futures are created by MISO and vetted by the MISO Planning Advisory Committee (PAC) stakeholder committee. Information for the production modeling dataset is sourced from Ventyx

and updated through an extensive MISO process to bring it into line with the most current data and expected future conditions. Coal unit retirements totaling 12.6 GW were included in the model per MISO's anticipated effects of prior EPA regulations.

Future EPA regulations, such as the recently proposed Clean Power Plan (111d) which is still in development, are not modeled nor considered in this study. The model footprint includes all areas in the Eastern Interconnect, with the exception of Florida, ISO New England and Eastern Canada.

For the Scenarios 1 and 2, new wind and solar generation was added at the locations determined in the siting task and transmission system upgrades/expansions were added per the conceptual transmission plans.

One aspect of the BAU set of assumptions is that many coal plants within MISO will continue to operate as they do now. That is, the plants remain on-line when economic market signals would have initiated a brief period of decommitment and effectively act as "must-run" units. In order to examine the sensitivity to changing this assumption, and to the assumption of coal unit retirements, Scenarios 1a and 2a were added to the production simulation analysis as sensitivity cases relative to Scenarios 1 and 2. Scenarios 1a and 2a included the following changes in assumptions:

- All coal units were economically committed
- Nine additional coal units in the Minnesota-centric region were assumed to be available (These units were assumed unavailable in Scenarios 1 and 2)
- Forced outage modeling of conventional generation was included

The production simulation results were analyzed to assess system operational performance with respect to the following parameters; annual energy production by type of generating resource, renewable energy resource utilization and curtailment, cycling duty of thermal plants, adequacy of ramping capability of the MISO generation fleet, and risk of reserve violations and unserved load. For Scenario 1, the results were also screened to select challenging operating conditions for dynamic performance, and these operating points were subsequently analyzed with fault simulations in the dynamics task.

1.6 Dynamic Performance Analysis

A dynamic simulation model was developed to perform transient stability analysis of the study scenarios. A series of dynamic data files were provided by the Minnesota utilities, based on the MTEP 2013 dataset. As with the power flow and production system models, new wind and solar generation was added at the locations determined in the siting task and transmission system upgrades/expansions were added per the conceptual transmission plans. In order to capture possible fault-induced delayed recovery issues caused by reduced levels of synchronous generation, the load models in the Minnesota-Centric region were refined to include a more detailed representation of load composition, including dynamic characteristics.

New utility-scale wind and solar photovoltaic (PV) plant models were consistent with current NERC and FERC minimum requirements (e.g. voltage regulation, power factor, voltage ride-through). Full commercial technical capability (e.g. synthetic inertia, frequency response) was not modeled. Distributed PV was modeled as lumped generation at locations (per the siting task) with no reactive power or voltage regulation capability.

New wind plants were split roughly 50/50 between Type 3 (double fed asynchronous generator (DFAG) and Type 4 (full converter).

A representative number of regional power system fault conditions were simulated to stress the system in different ways.

- Faults known to be severe challenges to system transient stability from numerous past stability studies,
- Faults in regions with high concentrations of wind and solar plants, where voltage recovery is highly dependent on the reactive power support from wind and solar plants.
- Faults affecting major transmission interfaces during periods of high power transfer

The results of all dynamic simulation cases were screened with respect to a set of performance criteria, including angular stability, oscillatory stability, voltage dips, and voltage recovery.

Weak system issues were also investigated using the dynamic system models. When the ac system impedance is high relative to the aggregate rating of wind and solar generation in a given region, the internal controllers and regulators within wind and solar inverters become less stable. If the system is excessively weak, control instabilities may occur. Composite short-circuit ratio analysis was conducted to determine system strength in the study scenarios with respect to emerging industry understanding of this issue.

1.7 Key Findings

This study examined two levels of increased wind and solar generation for Minnesota; 40% (represented by Scenarios 1 and 1a) and 50% (represented by Scenarios 2 and 2a). In the 40% Minnesota Scenario, MISO North/Central is at 15% (current state RESs). The 50% Minnesota Scenario also included an increase of 10% (to 25%) in the MISO North/Central region. Production simulation was used to examine annual hourly operation of the MISO North/Central system for all four of these scenarios. Transient and dynamic stability analysis was conducted for Scenarios 1 and 1a but not on Scenarios 2 and 2a.

1.7.1 General Conclusions for 40% RE Penetration in Minnesota

With wind and solar resources increased to achieve 40% renewable energy for Minnesota and 15% renewable energy for MISO North/Central, production simulation and transient/dynamic stability analysis results indicate that the system can be successfully operated for all hours of the year with no unserved load, no reserve violations, and minimal curtailment of renewable energy. This assumes sufficient transmission mitigations, as described in Section 1.4, to accommodate the additional wind and solar resources.

This is operationally achievable with most coal plants operated as baseload must-run units, similar to existing operating practice. It is also achievable if all coal plants are economically committed per MISO market signals, but additional analysis would be required to better understand implications, tradeoffs, and mitigations related to increased cycling duty.

Dynamic simulation results indicate that there are no fundamental system-wide dynamic stability or voltage regulation issues introduced by the renewable generation assumed in Scenario 1 and 1a. This assumes:

- New wind turbine generators are a mixture of Type 3 and Type 4 turbines with standard controls
- The new wind and utility-scale solar generation is compliant with present minimum performance requirements (i.e. they provide voltage regulation/reactive support and have zero-voltage ride through capability)
- Local-area issues are addressed through normal generator interconnection requirements

1.7.2 General Conclusions for 50% RE Penetration in Minnesota

With wind and solar resources increased to achieve 50% renewable energy in Minnesota and 25% renewable energy in MISO, production simulation results indicate that the system can be successfully operated for all hours of the year with no unserved load, no reserve violations, and minimal curtailment of renewable energy. This assumes sufficient transmission upgrades, expansions and mitigations to accommodate the additional wind and solar resources.

This is operationally achievable with most coal plants operated as baseload must-run units, similar to existing operating practice. It is also achievable if all coal plants are economically committed per MISO market signals, but additional analysis would be required to better understand implications, tradeoffs, and mitigations related to increased cycling duty.

No dynamic analysis was performed for the study scenarios with 50% renewable energy for Minnesota (Scenarios 2 and 2a) due to study schedule limitations and this analysis is necessary to ensure system reliability.

1.7.3 Annual Energy in the Minnesota-Centric Region

Figure 1-1 shows the annual load and generation energy by type for the Minnesota-Centric region. Comparing Scenarios 1 and 1a (40% MN renewables) with the Baseline,

- Wind and solar energy increases by 8.5 TWh, all of which contributes to bringing the State of Minnesota from 28.5% RE penetration to 40% RE penetration
- There is very little change in energy from conventional generation resources
- Most of the increase in wind and solar energy is balanced by a decrease in imports. The Minnesota-Centric region goes from a net importer to a net exporter.

Comparing Scenarios 2 and 2a (50% MN renewables) with Scenarios 1 and 1a (40% MN renewables),

- Wind and solar energy increases by 20 TWh. Of this total, 4.8 TWh brings the State of Minnesota from 40% to 50% RE penetration and the remainder contributes to bringing MISO from 15% to 25% RE penetration
- Most of the increase in wind and solar energy in the Minnesota-Centric region is balanced by a decrease in coal generation and an increase in net exports to neighboring regions
- Gas-fired, combined-cycle generation declines from 5.0 TWh in Scenario 1 to 3.0 TWh in Scenario 2.

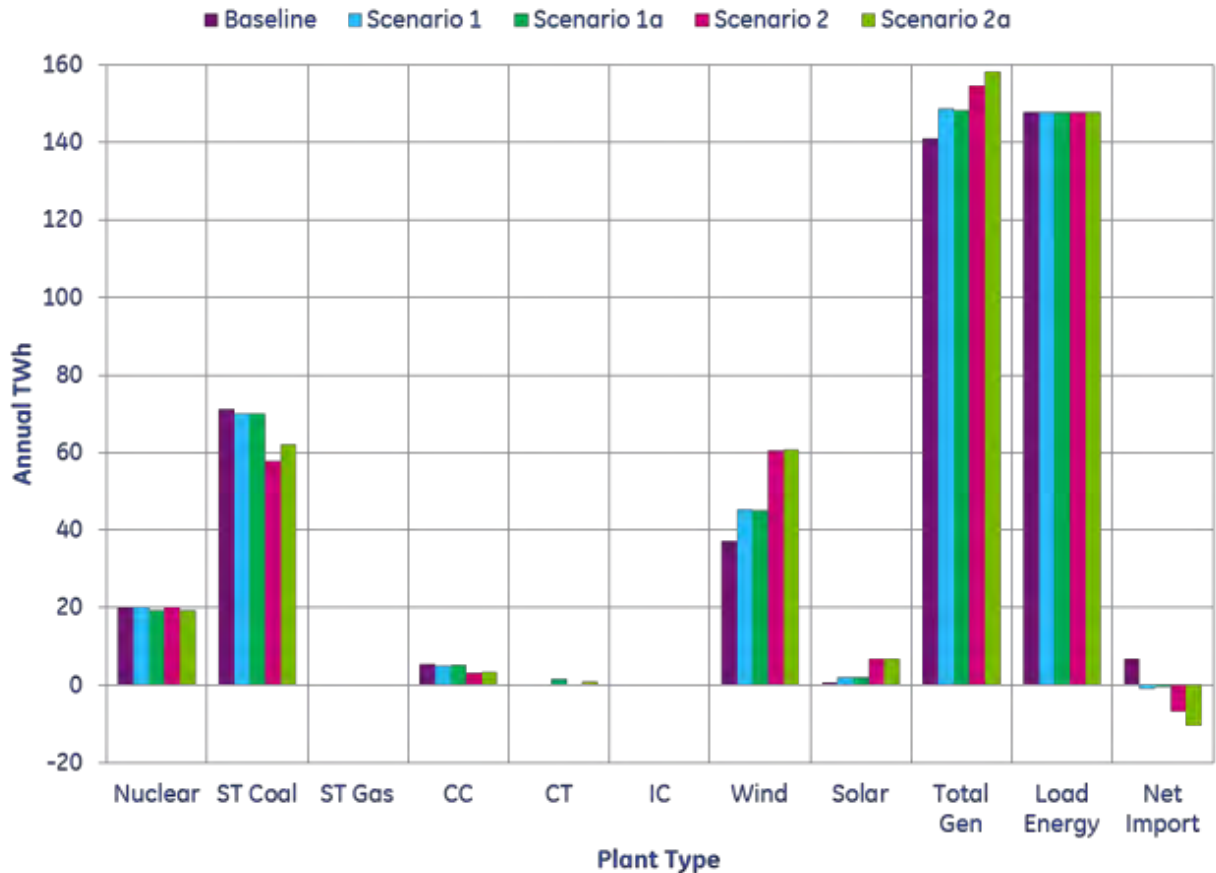


Figure 1-1 Annual Energy by Type in Minnesota-Centric Region for Study Scenarios

1.7.4 Cycling of Thermal Plants

Most coal plants were originally designed for baseload operation; that is, they were intended to operate continuously with only a few start/stop cycles in a year (mostly due to scheduled or forced outages). Increased cycling duty could increase wear and tear on these units, with corresponding increases in maintenance requirements. Many coal plants in MISO presently are designated by the plant's owner to operate as "must-run" in order to avoid start/stop cycles that would occur if they were economically committed by the market.

Scenarios S1a and S2a assumed that all coal plants in MISO are subject to economic commitment/dispatch (i.e., not must-run) based on day-ahead forecasts of load, wind and solar energy within MISO. Production simulation results show significant coal plant cycling due to economic market signals:

- Small coal units (below 300 MW rating) could have an additional 100 to 200 starts per year, beyond those due to forced or planned outages.
- Large coal units (above 300 MW) could have an additional 20 to 100 starts per year

Scenarios S1 and S2 assumed almost all coal plants would continue to operate as they do today. Coal units were on-line all year (except for scheduled maintenance periods) and were not decommitted during periods of low market prices. The results of these scenarios confirmed that the coal units could remain must-run with minor impacts on overall operation of the Minnesota-Centric region. Coal plant owners could choose to continue the must-run practice to avoid the detrimental impacts of increased cycling as wind and solar penetration increases. Doing so would likely incur some additional operational costs when energy prices fall below a plant's breakeven point. Wind curtailment would also be about 0.5% higher than if the coal plants were economically committed.

An attractive solution to the coal plant cycling issue may exist between the two bookend cases analyzed in this study. Scenarios 1a and 2a assumed that unit commitment was determined on a day-ahead basis, using day-ahead forecasts of wind and solar energy. The result was a high number of start/stop cycles of coal plants, sometimes with down-times of less than 2 days. If the unit commitment process was modified to use a longer term forward market (say 3 to 5 days ahead), then coal plant owners could adjust their operational strategy to consider decommitting units when prolonged periods of high wind/solar generation and low system loads are forecasted. A forward market would depend on longer term forecasts of wind, solar and load energy, consistent with the look-ahead period of the market. Although such forecasts would be somewhat less accurate than day-ahead forecasts, the quality of the forecasts would likely be adequate to support such unit commitment decisions.

This study did not examine the economic or wear-and-tear impacts of increased cycling on coal units. Further information on this topic can be found in the NREL Western Wind and Solar Integration Study Phase 2 report⁷ and the PJM Renewable Integration Study report⁸.

Combined-cycle (CC) units are better able to accommodate cycling duties than coal plants. Simulation results show that combined cycle units in the Minnesota-Centric region experience from 50 to 200 start/stop cycles per year. Cycling of CC units declines slightly as wind and solar penetration increases. This decline is primarily due to a decrease in CC plant utilization as wind and solar energy increases.

1.7.5 Curtailment of Wind and Solar Energy

In general, a small amount of curtailment is to be expected in any system with a significant level of wind and solar generation. There are some operating conditions where it is economically efficient to accept a small amount of curtailment (i.e., mitigation of that curtailment would be disproportionately expensive and not justifiable).

Overall curtailment in the Minnesota-Centric region is relatively small in all study scenarios, as shown in Table 1-2. Wind curtailment in Baseline and Scenario 1 is primarily due to local transmission congestion at a few wind plants. This congestion could be mitigated by transmission modifications, if economically justifiable.

Wind curtailment in Scenario 2 is due to system-wide operational limits during nighttime hours, when many baseload generators are dispatched to their minimum output levels. This type of curtailment could be reduced by decommitting some baseload generation via economic market

⁷ http://www.nrel.gov/electricity/transmission/western_wind.html

⁸ <http://www.pjm.com/committees-and-groups/task-forces/irtf/pris.aspx>

signals. The effectiveness of this mitigation option is illustrated by comparing Scenario 2 (coal units must-run) with Scenario 2a (economic coal commitment). Wind curtailment decreases from 2.14% to 1.60% (reduction of 332 GWh of wind curtailment). Solar curtailment decreases from 0.42% to 0.24% (reduction of 12 GWh of solar curtailment).

Table 1-2 Wind and Solar Curtailment for Study Scenarios

Scenario	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Wind Curtailment	0.42%	1.00%	1.59%	2.14%	1.60%
Solar Curtailment	0.09%	0.00%	0.23%	0.42%	0.24%

Note: Curtailment is calculated as a percentage of available annual wind or solar energy.

1.7.6 Other Operational Issues

No significant transmission system congestion was observed in any of the study scenarios with the assumed transmission upgrades and expansions. Transmission contingency conditions were considered in both the powerflow analysis used to develop the conceptual transmission system and the security-constrained economic dispatch in the production simulation analysis.

Ramp-range-up and ramp-rate-up capability of the MISO conventional generation fleet increases with increased penetration of wind and solar generation. Conventional generation is generally dispatched down rather than decommitted when wind and solar energy is available, which gives those generators more headroom for ramping up if needed.

Ramp-range-down and ramp-rate-down capability of the MISO conventional generation fleet decreases with increased penetration of wind and solar generation. In Scenario 2, there are 500 hours when ramp-rate-down capability of the conventional generation fleet falls below 100 MW/min. Periods of low ramp-down capability coincide with periods of high wind and solar generation. Wind and solar generators are capable of providing ramp-down capability during these periods. MISO's existing Dispatchable Intermittent Resource (DIR) process already enables this for wind generators. It is anticipated that MISO would expand the DIR program to include solar plants in the future.

1.7.7 System Stability, Voltage Support, Dynamic Reactive Reserves

No angular stability, oscillatory stability or wide-spread voltage recovery issues were observed over the range of tested study conditions. The 16 dynamic disturbances used in stability simulations included key traditional faults/outages as well as faults/outages in areas with high concentrations of renewables and high inter-area transmission flows. System operating conditions included light load, shoulder load and peak load cases, each with the highest percent renewable generation periods in the Minnesota-Centric region.

Overall dynamic reactive reserves are sufficient and all disturbances examined for Scenarios 1 and 1a show acceptable voltage recovery. The South & Central and Northern Minnesota regions get the majority of their dynamic reactive support from synchronous generation. Maintaining sufficient dynamic reserves in these regions is critical, both for local and system-wide stability.

Southwest Minnesota, South Dakota and at times Iowa get a significant portion of dynamic reactive support from wind and solar resources. Wind and Solar resources contribute significantly to voltage support/dynamic reactive reserves. The fast response of wind/solar inverters helps voltage recovery following transmission system faults. However, these are current-source devices with little or no overload capability. Their reactive output decreases when they reach a limit (low voltage and high current).

Synchronous machines (either generators or synchronous condensers), on the other hand, are voltage-source devices with high overload capability. This characteristic will strengthen the system voltage, allowing better utilization of the dynamic capability of renewable generation. The mitigation methods discussed below, namely stiffening the ac system through new transmission or synchronous machines, will also address this concern.

Local load areas, such as the Silver Bay and Taconite Harbor area, require reactive support from synchronous machines due to the high level of heavy industrial loads. If all existing synchronous generation in this region is off line (i.e. due to retirement or decommitment), reinforcements such as new transmission or synchronous condensers would be required to support the load.

Dynamic simulation results indicate that it is critical to maintain sufficient system strength and dynamic reserves to support high flows on the Northern Minnesota 500 kV lines and Manitoba high-voltage direct-current (HVDC) lines. Insufficient system strength and reactive support will limit Manitoba exports to the U.S. Existing transmission expansion plans, as modeled in this analysis, address these issues and are sufficient for the anticipated levels of Manitoba exports.

The Manitoba HVDC ties and the 500 kV transmission system in Northern Minnesota require reactive support from synchronous generators, the Dorsey and Riel synchronous condensers, and the Forbes static var compensator (SVC) to maintain the expected level of Manitoba exports. Without sufficient reactive reserves, the system could be unstable for nearby transmission disturbances. The current transmission plans, as modeled in this analysis, address this issue.

1.7.8 Weak System Issues

Composite Short-Circuit Ratio (CSCR) is an indicator of the ability of an ac transmission system to support stable operation of inverter-based generation. A system with a higher CSCR is considered strong and a system with a lower CSCR is considered to be weak. CSCR is calculated as the ratio of the composite short-circuit MVA at the points of interconnection (POI) of all wind/solar plants in a given area to the combined MW rating of all those wind and solar generation resources.

Low CSCR operating conditions can lead to control instabilities in inverter-based equipment (Wind, Solar PV, HVDC and SVC). Instabilities of this nature will generally manifest as growing voltage/current oscillations at the most affected wind or solar plants. In the worst conditions (i.e., very low CSCR), oscillations could become more wide-spread and eventually lead to loss of generation and/or damage to renewable generation equipment if not adequately protected against such events.

This is a relatively new area of concern within the industry. The issue has emerged as the penetration of wind generation has grown. Understanding of the fundamental stability issues is rapidly growing as more wind plants are being installed in regions with weak ac systems.

Equipment vendors, transmission planners and consultants are all working to gain a better understanding of the issues. Modeling and simulation tools have already been developed to enable detailed analysis of the phenomena. Wind and solar inverter control systems are being modified to improve weak system performance.

Synchronous machines (either generators or synchronous condensers) contribute short-circuit strength to the transmission system and therefore increase CSCR. Therefore, system operating conditions with more synchronous generators online will have higher CSCR. Also, stronger transmission ties (additional transmission lines or transformers, or lower impedance transformers) between synchronous generation and regions of wind and solar generation will increase CSCR. SVCs and STATCOMs do not contribute short-circuit current, and because they are electronic converter based devices with internal control systems similar to wind/solar inverters, their presence in a weak system region could further reduce the effective CSCR and exacerbate the control system stability issues that occur in weak system conditions.

There are two general situations where weak system issues generally need to be assessed:

- Local pockets of a few wind and solar plants in regions with limited transmission and no nearby synchronous generation (e.g. plants in North Dakota fed from Pillsbury 230 kV near Fargo).
- Larger areas such as Southwest Minnesota (Buffalo Ridge area) with a very high concentration of wind and solar plants and no nearby synchronous generation

This study examined the sensitivity of weak system issues in Southwest Minnesota. Observations are as follows:

The trouble spots identified in this analysis are not very sensitive to existing synchronous generation commitment. While there is very little synchronous generation within the area, the region is supported by a strong networked 345 kV transmission grid. Primary short circuit strength is from a wide range of base-load units in neighboring areas, and interconnected via the 345 kV transmission network. Commitment, decommitment or outages of individual synchronous generators do not have significant impact on CSCR in these identified areas.

Transmission outages will lower system strength and make the issue worse. When performing CSCR and weak system assessments as wind and solar penetration increases, it will be prudent to consider normal and design-criteria outages at a minimum (i.e, outage conditions consistent with MISO reliability assessment practices).

1.7.9 Mitigations

There are two approaches to improving wind/solar inverter control stability in weak system conditions:

- To improve the inverter controls, either by carefully tuning the equipment control functions or modifying the control functions to be more compatible with weak system conditions. With this approach, wind/solar plants can tolerate lower CSCR conditions.
- To strengthen the ac system, resulting in increased short-circuit MVA at the locations of the wind/solar plants. This approach increases CSCR.

The approaches are complementary, so the ultimate solution for a particular region would likely be a combination of both.

Mitigation through Wind/PV Inverter Controls

Standard inverter controls and setting procedures may not be sufficient for weak system applications. Loop gains of internal control functions inherently increase when system impedance increases, thereby reducing the stability margin of the controllers. Developers and equipment vendors must be made aware when new plants are being proposed for weak system regions so they can design/tune controls to address the issue. Wind plant vendors have made significant progress in designing wind and solar plant control systems that are compatible with weak system applications.

This approach becomes somewhat more difficult when there are wind/solar plants from multiple vendors in one region. The level of analysis requires detailed modeling of all affected wind plants at a level of detail that requires the use of proprietary control design information from the vendors. Vendors are very reluctant to share such data, except with independent consultants who can guarantee strict data security. However, this approach is gaining traction and a few projects have made effective implementations. The key to success is that project developers and equipment vendors must be informed beforehand that a given wind or solar plant will be installed at a weak system location. This enables the appropriate control design studies to be initiated before the project is installed.

In the event that such control-based approaches are not sufficient, it would be possible to further improve weak system performance by employing one or more of the system-level mitigations discussed below.

Mitigation by Strengthening the AC System

CSCR analysis of the Southwest Minnesota region shows that synchronous condensers located near the wind and solar plants would be a very effective mitigation for weak system issues. Synchronous condensers are synchronous machines that have the same voltage control and dynamic reactive power capabilities as synchronous generators. Synchronous condensers are not connected to prime movers (e.g. steam turbines or combustion turbines), so they do not generate power.

Other approaches that reduce ac system impedance could also offer some benefit:

- Additional transmission lines between the wind/solar plants and synchronous generation plants
- Lower impedance transformers, including wind/solar plant interconnection transformers

Series capacitors on transmission lines could be used to increase CSCR and to improve the transmission system's capability to transfer energy out of regions with high concentrations of wind and solar resources. However, series capacitors create subsynchronous frequency resonances in the transmission system which affect the performance of control systems within wind and solar plants. These resonances introduce an additional challenge to wind/solar plant control designs, which must maintain stable operation in the presence of the resonant conditions. Mitigation through

“must-run” operating rules for existing generation was found to be not very effective. The plants with synchronous generators are not located close enough to effected wind/solar plants.

2 PROJECT OVERVIEW

2.1 Background

In 2013 the Minnesota Legislature adopted a requirement for a Renewable Energy Integration and Transmission Study¹ (MRITS). The MN utilities and transmission companies, in coordination with MISO, conducted the engineering study. The Department of Commerce directed the study and appointed and led the Technical Review Committee (TRC). It is an engineering study of increasing the Minnesota Renewable Energy Standard to 40% by 2030, and to higher proportions thereafter, while maintaining system reliability.

The final study includes:

1. A conceptual plan for transmission for generation interconnection and delivery and for access to regional geographic diversity and regional supply and system flexibility, and
2. Identification and development of potential solutions to any critical issues encountered.

All utilities with Minnesota retail electric sales and all Minnesota transmission companies participated and/or were represented in the study. Eight Minnesota Local Balancing Authorities are represented and over 85% of the Minnesota retail sales are in the four largest Local Balancing Authorities: Xcel Energy (NSP), Great River Energy, Minnesota Power, and Otter Tail Power. The study area is within the NERC reliability region Midwest Reliability Organization (MRO). Nearly all of the Minnesota retail sales are within the Midcontinent Independent System Operator (MISO). The Local Balancing Authorities within MISO, including the Minnesota LBAs, are functionally consolidated.

Prior studies of relevance include the 2006 Minnesota Wind Integration Study², the 2007 Minnesota Transmission for Renewable Energy Standard Study³, the 2009 Minnesota RES Update, Corridor, and Capacity Validation Studies, the 2008 and 2009 Statewide Studies of Dispersed Renewable Generation⁴, the 2010 Regional Generation Outlet Study, the 2011 Multi Value Project Portfolio Study, the 2013 Minnesota Biennial Transmission Project Report⁵, the 2013 MISO Transmission Expansion Plan, and recent and ongoing MISO transmission expansion planning work⁶.

2.2 Objectives

1. Evaluate the impacts on reliability and costs associated with increasing Renewable Energy to 40% of Minnesota retail electric energy sales by 2030, and to higher proportions thereafter;

¹ MN Laws 2013, Chapter 85 HF 729, Article 12, Section 4; MPUC Docket No. CI-13-486.

² 2006 MN Wind Integration Study. Prepared for the MPUC, Nov 2006. Final Report Volumes I & II, Final Report Presentation. <http://www.puc.state.mn.us/PUC/electricity/013752>

³ "Minnesota RES Update Study Technical Report." March 2009. "RES Transmission Report." November 2007.

"Southwest Twin Cities – Granite Falls Transmission Upgrade Study Technical Report." March 2009.

"Capacity Validation Study Report." March 2009. <http://www.minnelectrans.com/reports.html>

⁴ Dispersed Renewable Generation Studies. June 2008 and September 2009.

<http://mn.gov/commerce/energy/topics/resources/Reports-Data/Energy-Reports.jsp>

⁵ <http://www.minnelectrans.com/>, November 1, 2013.

⁶ <https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx>

2. Develop a conceptual plan for transmission necessary for access to regional geographic diversity and regional system flexibility;
3. Identify and develop options to manage the impacts of the renewable energy resources;
4. Build upon prior wind integration studies and related technical work; Coordinate with recent and current regional power system study work;
5. Produce meaningful, broadly supported results through a technically rigorous, inclusive study process.

2.3 Study Timeline

June – August 2013

Commerce: Reviewed prior and current studies and worked with stakeholders and study participants to identify key issues, began development of a draft technical study scope, and accepted recommendations of qualified Technical Review Committee (TRC) members;

September 2013

Commerce: Held a stakeholder meeting to discuss the objectives, scope, schedule, and process; Commerce appointed the Technical Review Committee;

September / October 2013

Commerce, in consultation with the MN utilities, finalized the study scope;

October 2013

The MN utilities, in consultation with Commerce, identified the technical study team;

November 2013 – October 2014

The study was completed. The Technical Review Committee has reviewed all technical work in this study on an ongoing basis, throughout the study.

2.4 Study Scope

This study is focused on the reliability impacts of increased levels of variable renewables (wind and solar generation) and the associated costs of those impacts.

MRITS builds upon prior wind integration studies and related technical work and is coordinated with recent and current regional power system study work. The study scope was developed from statutory guidance, stakeholder input, and technical study team refinement.

MRITS incorporates three core and interrelated analyses: 1) *Power flow analysis* for development of a conceptual transmission plan, which includes transmission necessary for generation interconnection and delivery and for access to regional geographic diversity and regional supply and demand side flexibility; 2) *Production simulation analysis* for evaluation of operational performance, including reserve violations, unserved load, wind / solar curtailments, thermal cycling, and ramp rate and ramp range, and, to screen for challenging time periods; and 3) *Dynamics analysis*, which includes transient stability analysis and weak system strength analysis.

The MRITS study area is Minnesota-centric, which focuses on the combined operating areas of the Minnesota utilities and transmission companies, in the context of the MISO North/Central areas and the neighboring regions to the west and north.

The base study models (baseline and scenarios) are coordinated with and consistent with MISO models and databases including dispatch to the MISO market. Additional options were considered in Task 7 (Identify & Develop Mitigations / Solutions) as needed.

The key study tasks are:

- Develop Study Scenarios; Site Wind and Solar Generation (Task 1)
- Perform Production Simulation Analysis (Tasks 2 and 4)
- Perform Power Flow Analysis; Develop Transmission Conceptual Plan (Task 3)
- Evaluate Operational Performance (Task 6a)
- Screen for Challenging Periods; Perform Dynamics Analysis (Task 5 and 6b)
- Identify and Develop Mitigations and Solutions (Task 7)

The study task flow chart is shown in Figure 2-1.

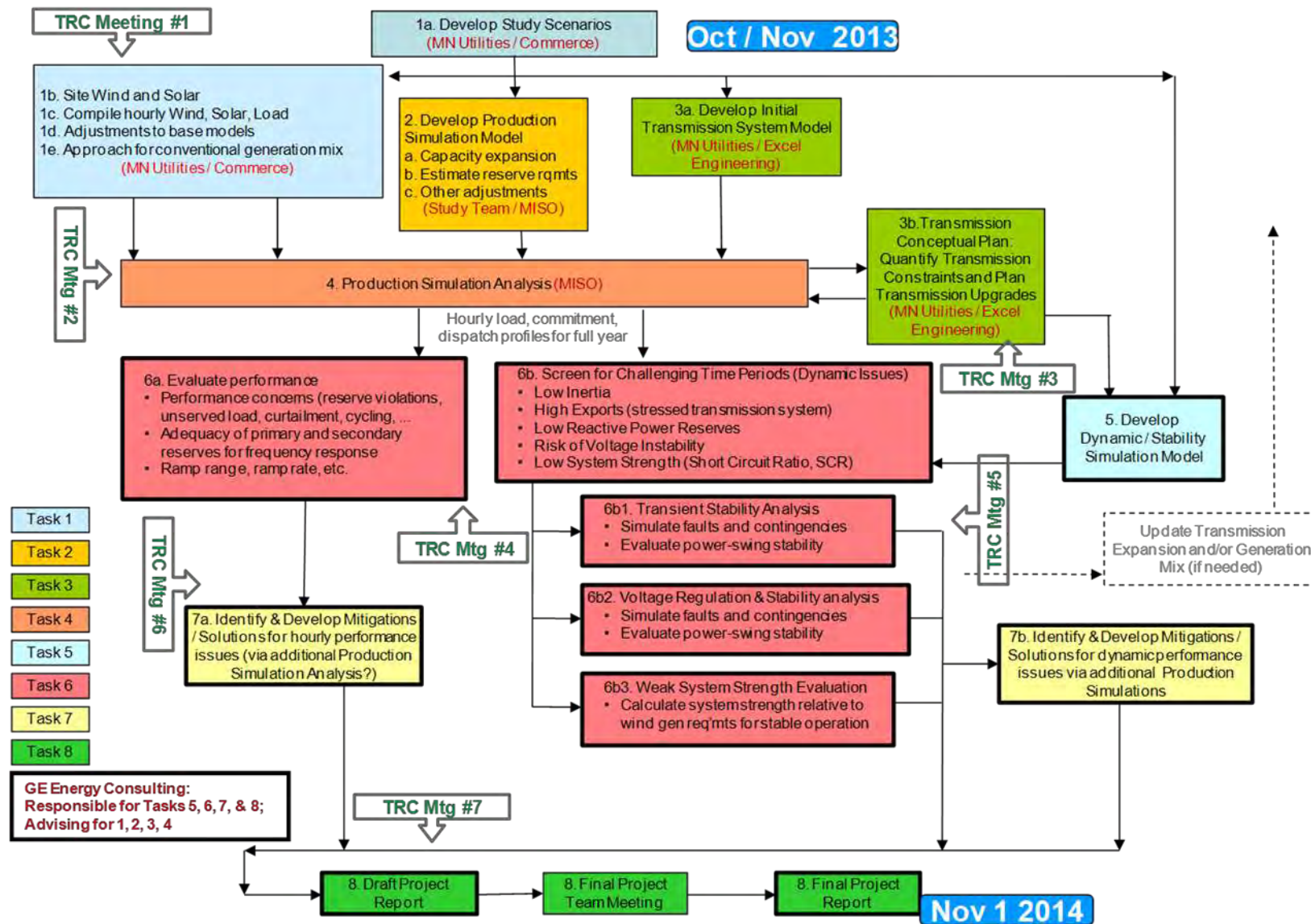


Figure 2-1 Flowchart of Project Tasks

2.5 Study Scenarios

The MRITS study scenarios were developed from statutory guidance, stakeholder input, and technical study team refinement.

The study year of 2028 was selected to help ensure that all models and system data were coordinated with and are consistent with MISO MTEP13 models and databases. It was also thought that 2028 was suitably near to 2030 as written in legislation, especially considering the difficulty in projecting an accurate load forecast fifteen years into the future.

Each of the study scenarios builds on the prior scenario, starting with the Baseline. The Baseline scenario has sufficient renewable energy generation to satisfy the current renewable energy standards and solar energy standards for all states in the study region. For Minnesota, the Baseline scenario was based on current Minnesota utility plans to meet the Minnesota Renewable Energy Standard (RES) and the Solar Energy Standard (SES) with renewable energy (wind, solar, small hydro, biomass, etc.) from the Minnesota-centric area and incorporates refinements from the technical study team. For non-Minnesota MISO states in the study footprint, the Baseline scenario was based on the prior approved 2013 MISO Transmission Expansion Plan (MTEP13).

1. Scenario 1 builds on the Baseline scenario by adding incremental wind and solar (variable renewables) generation to the Baseline model to supply a total of 40% of Minnesota annual electric retail sales from renewables in the study year with all states at full implementation of their current RESs.
2. Scenario 2 builds on Scenario 1 by adding incremental wind and solar generation to the Scenario 1 model to supply 50% of Minnesota electric retail sales from total renewables and by further adding incremental wind and solar generation to supply an additional 10% of the non-Minnesota MISO North / Central retail electric sales from total renewables (i.e. to increase the MISO footprint renewables 10% above full implementation the current RESs).

Model	Minnesota	MISO North/Central (includes MN)
Baseline	28.5%	14.0%
Scenario 1	40.0%	15.0%
Scenario 2	50.0%	25.0%

Within each of the scenarios, the allocation of the RES was further divided between wind and solar resources and within the solar allocation was divided between centralized utility sized solar (UPV) and distributed small PV (DPV).

It was assumed that the growth in energy sales for Minnesota and MISO (includes Minnesota) would increase by 0.5% and 0.75% respectively. Given these assumptions and the allocation of resources for each scenario, Table 2-1 describes the amount of additional wind and solar resources included in the models.

Table 2-1 Wind and Solar Resource Allocations for Study Scenarios

	2013	2028				
MN Retail Sales (GWH)	66,093	71,227				
		Wind MW		PV MWac		
Minnesota-centric	Wind (MW)	Total	Incremental	Total	Incremental	
Existing + signed GIA	8,922				UPV	DPV
Baseline		5,990		457	361	96
Scenario 1		7,521	1,931	1,371	723	191
Scenario 2		8,131	610	4,557	2,756	430

	2013	2028				
MISO Retail Sales (GWH)	498,000	557,000				
		Wind MW		PV MWac		
MISO (includes Minnesota)	Wind (MW)	Total	Incremental	Total	Incremental	
Existing + signed GIA	15,320				UPV	DPV
Baseline		22,229	6,900	1509	1,413	96
Scenario 1		24,160	1,931	2,442	723	210
Scenario 2		37,796	13,636	6,201	5,636	565

Note that Minnesota Baseline renewable percentage includes qualifying small hydro and biomass. MISO retail sales and percentages are MISO North and Central (they do not include MISO South).

Minnesota wind generation was sited Minnesota-centric (Minnesota, North Dakota, South Dakota, and northern Iowa). Minnesota solar generation was sited in Minnesota, eastern South Dakota and northern Iowa. MISO wind and solar generation was sited per the MISO Transmission Expansion Planning assumptions. The generation siting process and assumptions are described in greater detail in subsequent sections of this report.

3 WIND AND SOLAR GENERATION SITING

Per the project plan, this task focused on selecting sites for wind and solar resources to meet the requirements of the study scenarios. Minnesota wind and solar resources were sited in the Minnesota-centric area (MN, ND, SD, northern Iowa) based on existing wind and solar, planned wind and solar (including those with signed Interconnection Agreements, wind sites in MVP portfolio planning), and MN utility announced projects. Wind and solar resources in the interconnection queues also helped inform the siting selection process.

MISO future wind and solar was sited per MTEP guidelines (e.g. at expanded RGOS zones on a pro rata basis).

As described in the previous chapter, there are significant amounts of new wind and solar generation to locate in Minnesota and within MISO for the study scenarios. Table 3-1 and Table 3-2 show the Minnesota and MISO wind and solar build-outs for the Baseline, Scenario 1 and Scenario 2 cases to be studied. Table 3-3 shows the key assumptions that were used during the build-out process.

Table 3-1 Minnesota-Centric Wind and Solar Amounts to be Sited

	Minnesota Centric			
	Wind MW	PV MWac		
	Incremental	Incremental		Total
		Utility PV	Distributed PV	
Baseline		361	96	457
Scenario 1	1,931	723	191	914
Scenario 2	610	2,756	430	3186

Table 3-2 Non-MN-Centric Wind and Solar Amounts to be Sited

	Non-MN MISO			
	Wind MW	PV MWac		
	Incremental	Incremental		Total
		Utility PV	Distributed PV	
Baseline	6900	1052	0	1052
Scenario 1	0	0	19	19
Scenario 2	13026	2,880	135	3015

Table 3-3 Key assumptions for Wind & Solar Build-Outs

Wind Annual Capacity Factor	Utility Scale PV		Residential & Commercial PV	
	Central		Distributed	
	CPV		DPV	
	fraction	Annual Capacity Factor (AC)	fraction	Annual Capacity Factor (AC)
Minnesota				
38%				
38%	80%	18%	20%	17%
42%	80%	18%	20%	17%
42%	85%	18%	15%	17%
MISO				
32%				
37%	90%	17%	10%	16%
37%	90%	17%	10%	16%
37%	90%	17%	10%	16%
PV assumptions: - S1 20% distributed, 80% centralized - S2 15% distributed, 85% centralized				

3.1 Siting for Wind Resources

The wind profile data used in this study were derived from existing wind data sets from NREL. The data set are for the years, 2004, 2005 and 2006 and was initially developed for Eastern Wind Integration and Transmission Study (EWITS) and updated for Eastern Renewable Generation Integration Study (ERGIS) on hourly and 10 minutes intervals. MISO had been using the data set year 2005 but downloaded and updated their data using the updated ERGIS 2006 data set.

MISO also added recently signed Generation Interconnection Agreements for Xcel Energy and MidAmerican Energy Company (MEC) wind generation projects and these reduced the MN, ND & IA future/proxy wind to compensate for the addition. MISO also minimized wind siting at RGOS Zones

MN-E, MN-H, MN-L, WI-F and allowed non-MN MISO wind, to serve non-Minnesota MISO state RPSs, to include MN sited wind generation. The MISO wind was then prorated on the projected 2018, 2023 and 2028 additions. Bus names and bus numbers were corrected accordingly.

3.1.1 Minnesota Wind

Minnesota Wind is intended to serve the Minnesota RES and is sited in the Minnesota-centric area which includes all of Minnesota, parts of North Dakota and South Dakota as well as northern Iowa.

A For the Baseline Model

MTEP13 siting principles which uses the current MISO state RPSs, and corresponding wind siting including the existing and planned wind sites. (Table 3-4)

B For Scenario 1

Adding 1931 MW into the Minnesota-centric area and sited per Minnesota wind resource and consistent with expanded MISO renewable energy (MVP/RGOS) zones (see Table 3-5). Xcel Energy had recently signed Generation Interconnection Agreements for four wind plants totaling 750 MW and this was included in the 1931 MW and these locations are shown in green in Figure 3-2.

C For Scenario 2

Minnesota wind for Scenario 2 was increased by 610 MW above what was in Scenario 1. See Table 3-6.

3.1.2 MISO (non-MN) Wind

Non-MN Wind is intended to serve the MISO state RPSs for states other than Minnesota. The wind resources are sited per MTEP wind resource in the MISO footprint including in the Minnesota-Centric Area.

A For Baseline

Beyond the wind included in the MTEP 2013 models, which includes the existing and planned wind projects in MISO, 6900 MW was added MISO wide to meet the current MISO state RPSs (including MN). This is shown in Table 3-2.

B For Scenario 1

No non-MN MISO wind was added.

C For Scenario 2

Beyond the Baseline, 13,026 MW of non-Minnesota wind was added baseline in the RGOS zones primarily in Iowa, Illinois, Indiana and Michigan (see Table 3-8). MEC had recently signed generation interconnection agreements for four wind plants totaling 932.6 MW and this was included in the 13,026 MW total. These four locations are shown in green in Figure 3-3.

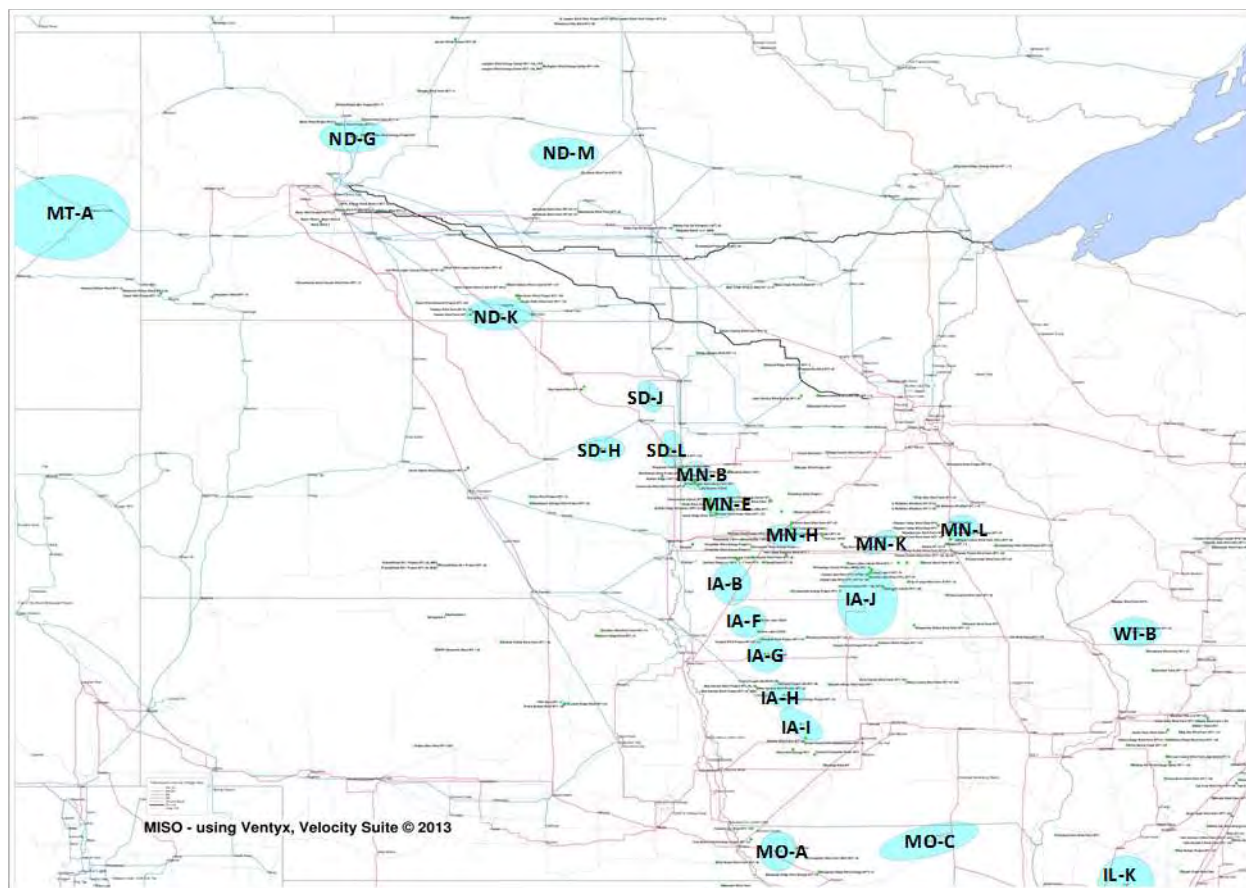


Figure 3-1 RGOS Wind Zones

Table 3-4 MISO Wind Locations-Baseline

RGOS Zone	Bus Name	Existing and Signed GIAs (MW)	MISO - Baseline Wind Additions (MW)			Total wind amounts in Baseline Scenario (MW)
			2018	2023	2028	
IA-B	SHELDON	610	23	63	239	934
IA-F	SHELDON	675	23	61	233	992
IA-G	RAUN	805	21	56	214	1096
IA-H	GRIMES	415	17	45	170	647
IA-I	GRIMES	383	10	26	101	520
IA-J	WEBSTER	1735	1	4	14	1754
IL-F	BROKAW	891	126	48	21	1085
IL-K	PAWNEE	420	94	71	0	585
IN-E	WESTWD	350	11	30	115	507
IN-K	HORTVL	200	15	40	154	409
MI-B	REESE	305	378	0	0	683
MI-C	WYATT	233	345	0	0	579
MI-D	WYATT	112	278	0	0	390
MI-E	REESE	333	378	0	0	711
MI-F	WYATT	32	378	0	0	410
MI-I	PALISADES		191	0	0	191
MN-B	LYON COUNTY	985	6	16	60	1066
MN-E	CHANARAMBIE	891				891
MN-H	LAKEFIELD	553				553
MN-K	HUNTLEY	1251	14	36	140	1441
MN-L	PLEASANT VALLEY	813				813
MO-A	ATCHISON T	146	224	0	0	370
MO-C	ADAIR		314	0	0	314
MT-A	BAKER	200	11	28	107	345
ND-G	GRE-MCHENRY	780	16	41	156	994
ND-K	ELLEDALE	171	13	34	130	348
ND-M	GRE-RAMSEY	887	4	12	48	952
SD-H	BIG STONE SOUTH (West of)		23	63	239	324
SD-J	BIG STONE SOUTH	40	23	61	232	355
SD-L	BROOKINGS	207	23	63	239	531
WI-B	DUBUQUE CTY	121	18	49	186	374
WI-D	NORTH APPLETON	267	20	54	203	543
WI-F		520.6	0	0	0	521
Totals		15,329	3000	900	3000	22,229

Table 3-5 Incremental Minnesota-Centric Wind Locations for Scenarios 1&2

RGOS Zone	Bus Name	Incremental MN Wind for Scenario 1	Incremental MN wind for Scenario 2	Total Scenario 1 & 2 Incremental MN wind
IA-B	SHELDON	125	50	175
IA-J	WEBSTER	75	10	85
MN-B	LYON COUNTY	218	191	409
MN-E	CHANARAMBIE	50		50
MN-H	LAKEFIELD	125		125
MN-K	HUNTLEY	150	129	279
MN-L	PLEASANT VALLEY	75		75
MN	ODELL (G826)	200		200
MN	PLEASANT VALLEY (J278)	200		200
ND-G	GRE-MCHENRY	0	80	80
ND-K	ELLEDALE	50		50
ND-M	GRE-RAMSEY	25	30	55
ND	BORDERS (J290)	150		150
ND	COURTNEY (J262/J263)	200		200
SD-H	BIG STONE SOUTH (West of)	50		50
SD-J	BIG STONE SOUTH	108	50	158
SD-L	BROOKINGS	130	70	200
Totals		1931	610	2541

Table 3-6 Minnesota-Centric Wind Siting

State	Baseline Scenario	Incremental MN Wind gen for Scenario 1	Incremental MN Wind gen for Scenario 2	Total Incremental Wind Scenario 1 & 2
IA %	24.5%	10.4%	9.8%	10.2%
MN %	43.5%	52.7%	52.5%	52.7%
ND %	20.9%	22.0%	18.0%	21.1%
SD %	11.1%	14.9%	19.7%	16.1%

Table 3-7 Non Minnesota MISO Wind Locations- Scenario 1 & 2

RGOS Zone	Bus Name	Incremental Non-MN Wind for Scenario 1	Incremental Non-MN Wind for Scenario 2
IA-B	SHELDON		361
IA-F	SHELDON		397
IA-G	RAUN		350
IA-H	GRIMES		240
IA-I	GRIMES		67
IA-J	WEBSTER		25
IA	HIGHLAND (R39)		500
IA	LUNDGREN (R42)		250
IA	VIENNA II (H009)		44
IA	WELLSBURG (H021)		138.6
IL-F	BROKAW		398
IL-K	PAWNEE		345
IN-E	WESTWD		329
IN-K	HORTVL		425
MI-B	REESE		736
MI-C	WYATT		676
MI-D	WYATT		552
MI-E	REESE		736
MI-F	WYATT		736
MI-I	PALISADES		391
MN-K	HUNTLEY		261
MO-A	ATCHISON T		453
MO-C	ADAIR		620
MT-A	BAKER		309
ND-G	GRE-MCHENRY		353
ND-K	ELLENDAL		367
ND-M	GRE-RAMSEY		130
SD-H	BIG STONE SOUTH (West of)		638
SD-J	BIG STONE SOUTH		571
SD-L	BROOKINGS		568
WI-B	DUBUQUE CTY		507
WI-D	NORTH APPLETON		550
WI-F			0
	Totals	0	13,026

Table 3-8 Non-MN MISO Wind Siting

State	Baseline Scenario	Incremental Non-MN Wind for Scenario 1	Incremental Non-MN Wind for Scenario 2
IA %	26.7%	n/a	18.2%
IL %	7.5%	n/a	5.7%
IN %	4.1%	n/a	5.8%
MI %	13.3%	n/a	29.4%
MN %	21.4%	n/a	2.0%
MO %	3.1%	n/a	8.2%
MT %	1.6%	n/a	2.4%
ND %	10.3%	n/a	6.5%
SD %	5.4%	n/a	13.6%
WI %	6.5%	n/a	8.1%

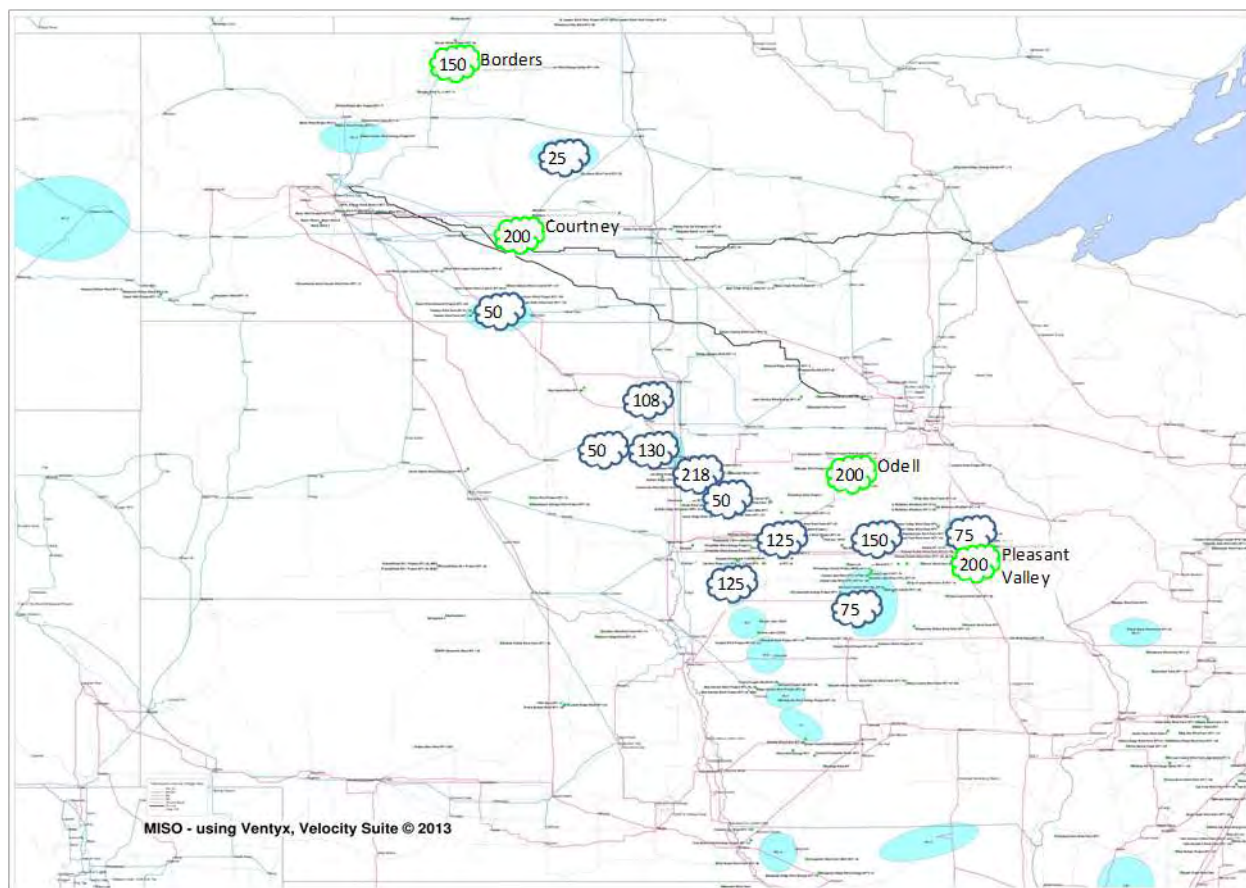


Figure 3-2 MN & Non MN Scenario 1 Wind Siting

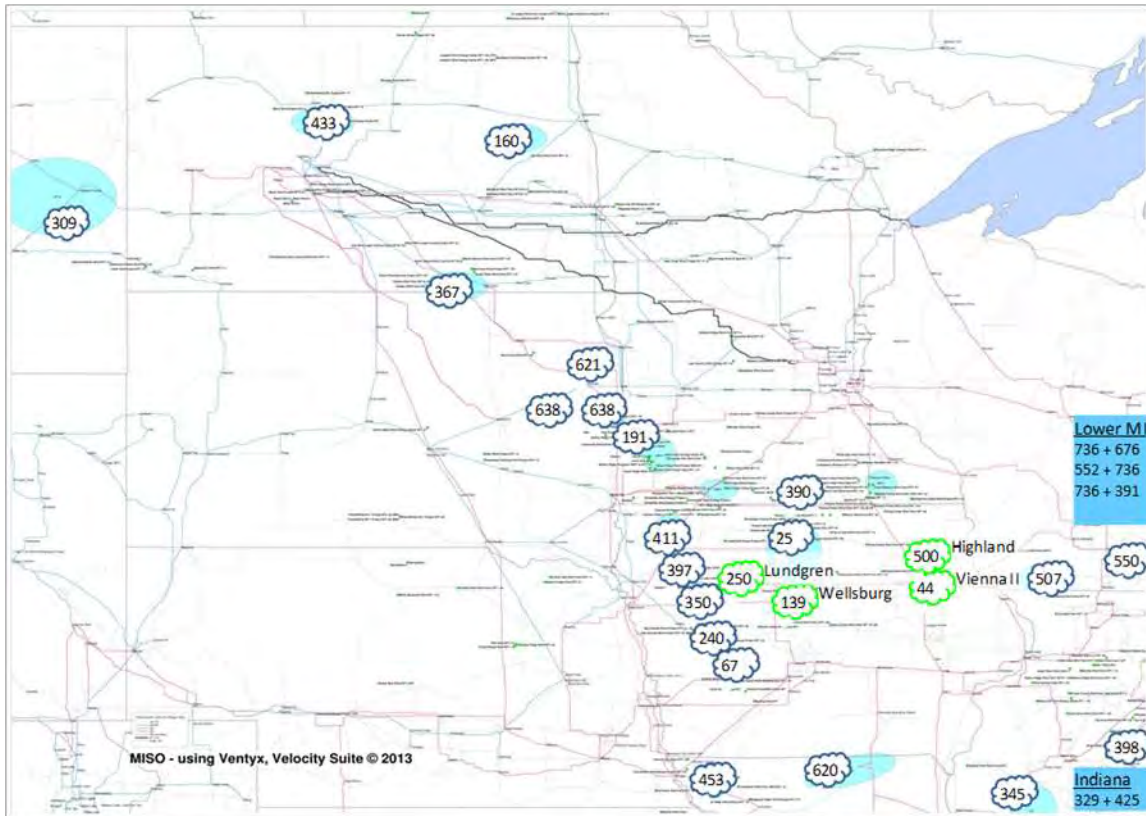


Figure 3-3 RGOS Wind Zones w/MN & Non MN Scenario 2

3.2 MISO Wind Reassignment

The Non-MN MISO wind was sited per as described in the previous section. However after the production simulation analysis showed significant amounts of wind congestion at some plants in western MISO, it was decided to relocate some of this congested wind sites to less congested areas. A portion of the wind generation was moved from the “Top 4” congested sites and reassigned to the “Bottom 10” least congested sites.

This reassigned generation only involved the non-MN MISO wind and this generally relocated the wind generation to the south and east locations with lower capacity factor. As a result of the placing this generation at sites with lower capacity factors, or reduced average wind speeds, the wind nameplate had to be increased in order to maintain the equivalent wind energy prior to and after the shift.

Table 3-9 displays the shifted sites, nameplate capacity and annual energy outputs. Figure 3-4 shows the locations of the wind sites that were shifted; the sites in red represent the 4 most congested sites. The wind resources from these locations were shifted to the sites shown in yellow.

Table 3-9 Wind Shift from the 4 Most-Congested to the 10 Least-Congested Sites

Zone	Company	Basecase (MW)	S1 (MW)	S2 (MW)	Basecase Curtailment (GWh)	S1 Curtailment (GWh)	S2 Curtailment (GWh)	S2 Capacity Adjustment (MW)	S2 Energy Adjustment (GWh)
SD-H:1	OTP	324	374	1,012	25.7	0.9	1,226.6	(311)	(1,229)
ND-K:1	MDU	177	227	595	5.0	26.3	895.2	(293)	(898)
IA-G:1	MEC	292	292	642	0.6	1.7	495.6	(129)	(499)
MN-K:1	Alliant West	190	340	731	3.7	30.9	444.4	(118)	(447)
								(851)	(3,293)
H009:1	MEC	-	-	44	-	-	0.3	83	329
H021:1	Alliant West	-	-	139	-	-	0.1	97	329
IL-F:1	Ameren IL	194	194	591	-	-	-	106	329
IN-E:1	Duke Energy IN	157	157	486	-	-	-	103	329
MI-C:1	Detroit Edison	345	345	1,022	-	-	-	111	329
MI-B:1	Detroit Edison	378	378	1,114	-	-	-	89	329
MI-F:1	Detroit Edison	378	378	1,114	-	-	-	98	329
MI-E:1	Detroit Edison	378	378	1,114	-	-	-	80	329
MI-I:1	Consumers Energy	191	191	582	-	-	-	84	329
MI-D:1	Detroit Edison	278	278	830	-	-	-	96	329
								947	3293
							Net	96	0

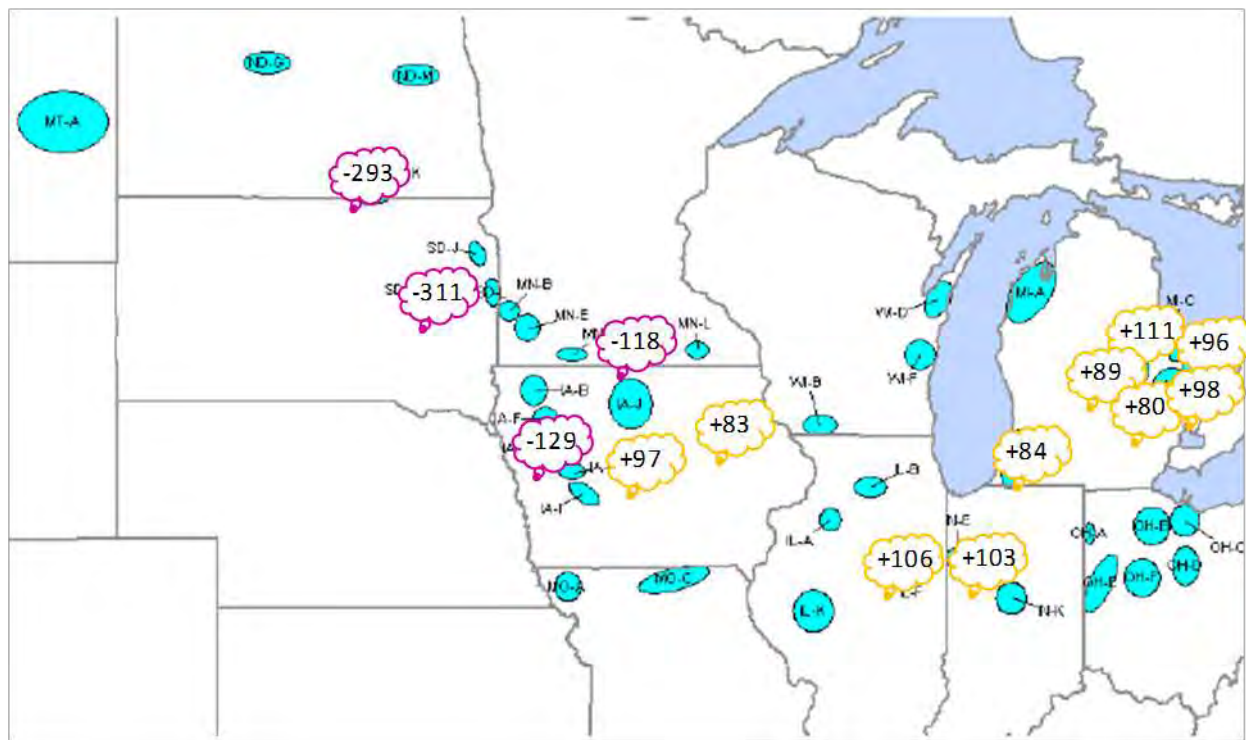


Figure 3-4 Wind Shift from the 4 Most-Congested to the 10 Least-Congested Sites

3.3 Siting of PV Solar Resources

The Non-Minnesota MISO photovoltaic solar data set came from the ERGIS hourly solar data. For Minnesota solar data, NREL developed additional 2006 hourly solar power data with 10 km resolution, which allow the siting of additional utility-scale solar in Minnesota that was not present in the ERGIS data.

For utility-scale solar plants in Minnesota, the data was processed to create individual solar plants simulating a 1.25:1 module-to-inverter ratio. This was done to approximate the additional solar panels that are used to reduce the losses and increase the capacity factor of utility-scale solar plants by having the capacity of the photovoltaic panels exceed the capacity of the inverter. This process involved setting the ac rating at 80% of the dc nameplate rating and clipping the output to the ac rating. (For example, the raw values for a 50 MWdc PV plant were limited to 40 MWac to create a 40 MW plant for the study.) The capacity values were revised accordingly so they reflect the ac bus bar values.

The ERGIS data already contained values for the utility-scale solar plants outside of Minnesota and the distributed solar (both inside and outside of Minnesota). These values reflected typical losses due to inverter efficiency and other factors. The distributed solar dc to ac losses varied from 79% to 85% with an average of 82%. Non-Minnesota utility-scale solar losses varied from 77% to 89% with an average of 83%. However the assumed annual energy numbers remain the same because the ac ratings are based on the maximum output value for each site rather than the dc values.

3.3.1 Minnesota PV Solar

The solar generation added in the Minnesota-Centric area was split between Distributed PV and Centralized utility scale PV on a 20%/80% basis for the Baseline and Scenario 1, and a 15%/85% split for Scenario 2, respectively. The 1.5% solar mandate enacted in 2013 legislation dictated that at least 10% of the solar was to be distributed, but the splits were determined in the stakeholder study scoping process. The distributed PV was assumed to be sited at load centers.

The Centralized utility scale PV was spread by solar resource largely over the southern half of Minnesota, however there was some sited in the northern portion of the state as utilities in the northern part of the state indicated that they would prefer to site closer to their service territory even knowing that the energy output would be slightly less than the southwest portion of the state. Note: there is an approximately 10% decrease in solar resource strength from the south west corner of MN to Duluth, MN in the north east. The solar strength does not follow an intuitive rule where further south equals stronger solar strength, but rather the solar strength gradient generally follows a NW to SE line, such that Alexandria, MN has about the same solar value as the Twin Cities. This is shown in Figure 3-5.

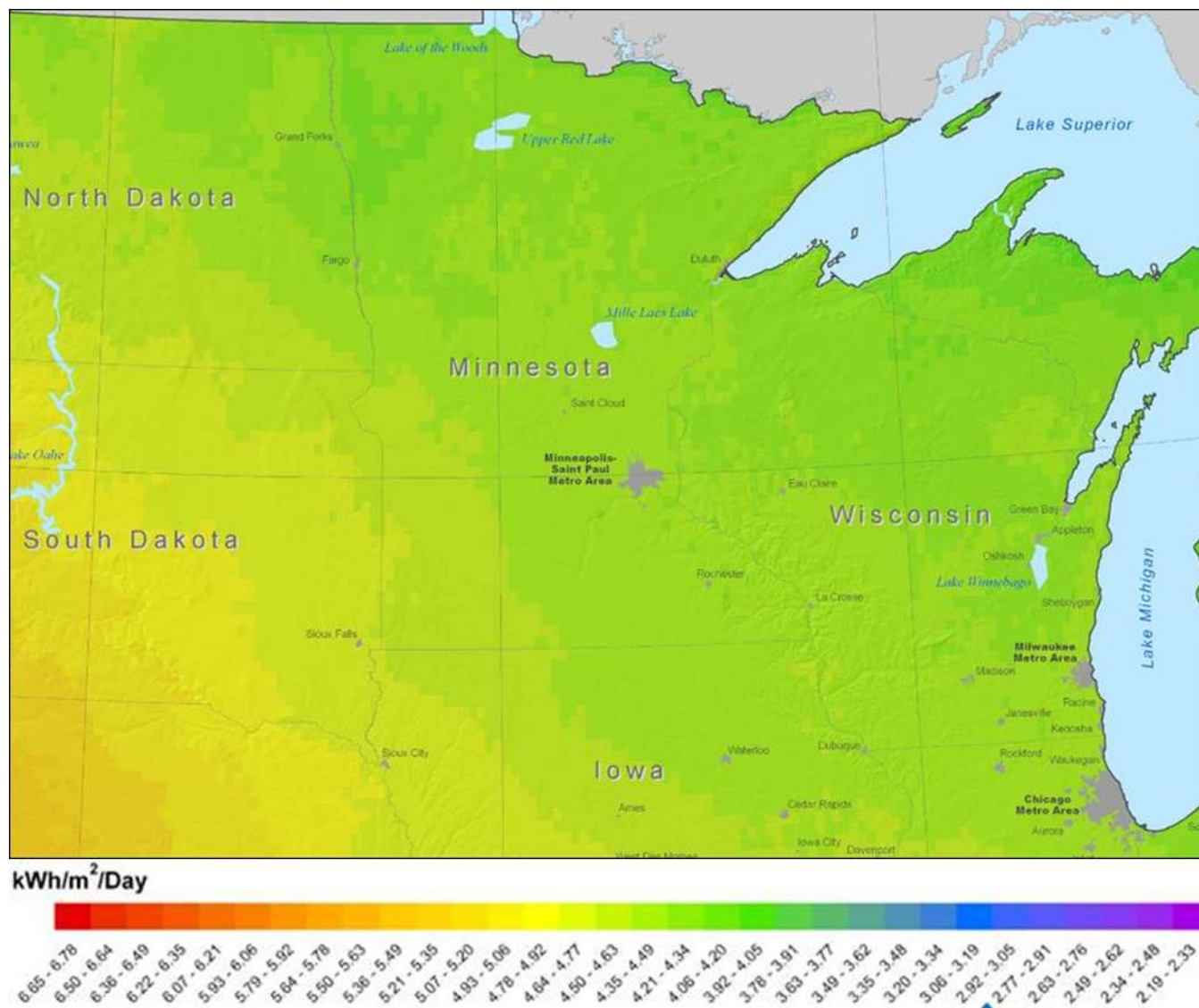


Figure 3-5 United States Photovoltaic Solar Resource (portion of)

- For the Baseline scenario, a total of 457 MWac PV was added with 96 MW being distributed and 361 MW classified and sited as Utility scale solar.
- For Scenario 1, a total of 914 MWac PV was added with 191 MW being distributed and 723 MW classified and sited as Utility scale solar.
- For Scenario 2, a total of 3,186 MWac PV was added with 430 MW being distributed and 2,756 MW classified and sited as Utility scale solar.

These solar generation amounts are shown in Table 3-10 and Table 3-11. The locations are shown in Figure 3-6, Figure 3-7, and Figure 3-8.

Table 3-10 Minnesota Utility PV Sites for Study Scenarios

Location	Baseline	Scenario 1	Scenario 2	Total at each site
Riverton 230	2	5	5	12
Badoura 230	3	8	10	21
Hubbard 230	5	10	15	30
Wing River 230	5	10	15	30
Alexandria 345	20	20	50	90
Quarry 345		30	80	110
Chub Lake 345	20	20	100	140
Prairie Island 345		30	100	130
North Rochester 345		30	100	130
Byron 345	20	20	100	140
Pleasant Valley 345	20	30	100	150
Sheas Lake 345	20	30	100	150
Owatanna 115			50	50
Wilmarth 345		50	100	150
Adams 345	20	30	100	150
Hayward 161			51	51
Cedar Mountain 345	20	30	100	150
Willmar 230			80	80
Big Stone South 345	20	30	100	150
Hazel 345	20	30	100	150
Lyon County 345	20	30	100	150
Fort Ridgley 115			50	50
Chanarambie 115			50	50
Fox Lake 161			50	50
Winnebago(Huntley) 345	30	40	100	170
Brookings 345	26	40	100	166
West New Ulm 115			50	50
Lakefield 345	30	40	100	170
Pipestone 115			50	50
Nobles 345	30	40	100	170
Split Rock 345	30	40	150	220
Ledyard, IA 345		40	200	240
Obrien, IA 345		40	200	240
Totals	361	723	2756	3840



Figure 3-6 MN Solar for Utility Locations - Baseline

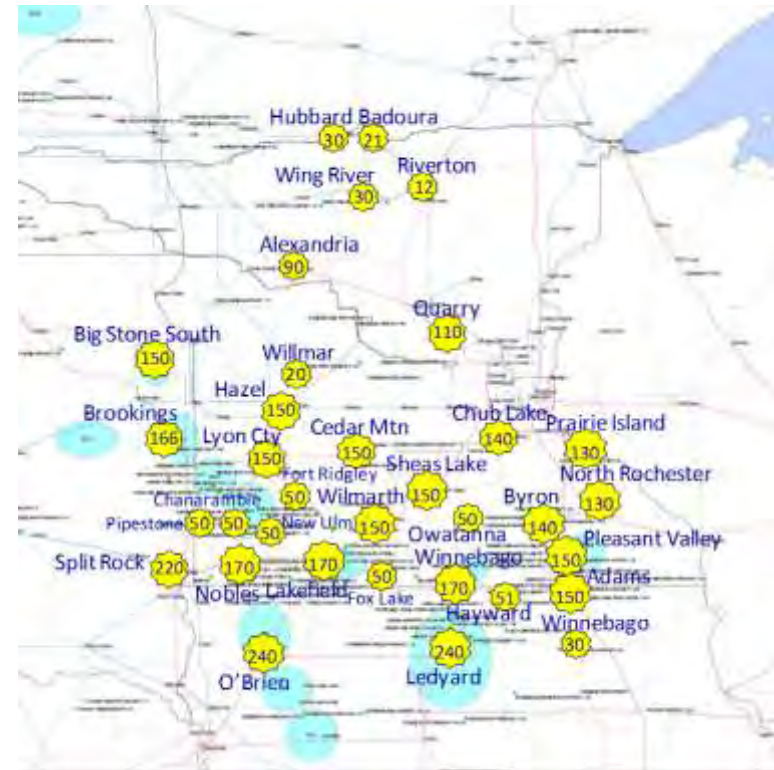


Figure 3-7 MN Solar for Utility Locations - All Scenarios

Table 3-11 MN Distributed PV Sites for Study Scenarios

Location	Baseline	Scenario 1	Scenario 2	Total at each site
	MW (AC)			
NORTHERN HILLS	4	6	15	25
SOUTH FARIBAULT	2	4	9	15
CANNON FALLS	3	9	21	33
INVER HILLS	6	12	28	46
BLUE LAKE	4	9	18	31
GRE-MCLEOD	3	5	13	21
TERMINAL	9	34	30	73
PARKERS LAKE	14	24	92	130
AS KING	8	14	32	54
BLAINE	3	6	14	23
COON CREEK	8	10	24	42
DICKINSON	4	7	16	27
ELM CREEK	2	4	9	15
KOLMAN LAKE	4	7	16	27
BLAINE	4	7	16	27
ELK RIVER	4	7	16	27
ELM CREEK	2	4	9	15
CHISAGO	4	7	16	27
SHERBURNE CTY	3	5	13	21
RUSH CITY	2	3	7	12
PAYNESVILLE	3	7	16	26
Totals	96	191	430	717

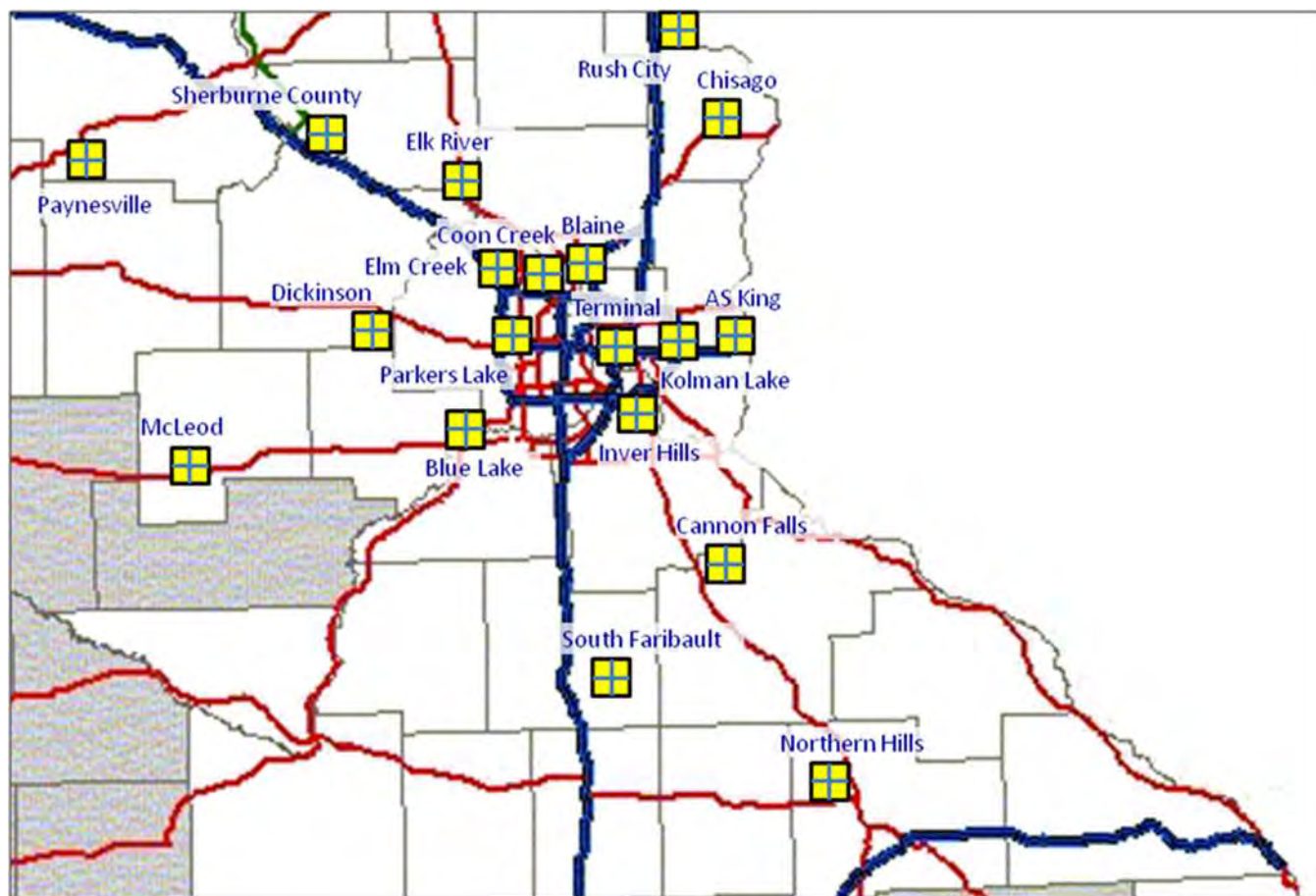


Figure 3-8 MN Distributed PV Sites

3.3.2 Non-Minnesota PV Solar

MISO solar was sited at ERGIS solar data set locations with a fixed 10%/90% split between Distributed PV and Central utility scale PV and this split was also determined in the stakeholder study scoping process.

- For the Baseline no solar was added.
- For Scenario 1, a total of 19 MWac of distributed PV was added.
- For Scenario 2, a total of 3,015 MWac PV was added with 135 MW being distributed and 2,880 MW classified and sited as Utility scale solar.

These solar generation amounts are shown in Table 3-12 and Table 3-13. The locations are shown in Figure 3-9.

Table 3-12 Non-MN Solar for Utility Locations

State	Baseline	Scenario 1	Scenario 2	Total at each site
	<u>MW (AC)</u>			
Michigan	126	0	189	315
Indiana	239	0	521	681
Illinois	188	0	377	572
Iowa	39	0	55	94
Missouri	431	0	1583	2079
Arkansas	7	0	39	48
Kentucky	22	0	116	143
Totals	1052	0	2880	3932

Table 3-13 Non-MN Distributed Solar for Study Scenarios

Location		Baseline	Scenario 1	Scenario 2	Sub-totals	Totals
	<u>City</u>	<u>MW (AC)</u>				
MI	Detroit	0	1	6	7	31
	Flint	0	0	4	4	
	Grand Rapids	0	1	6	7	
	Ann Arbor	0	1	6	7	
	Lansing	0	1	5	6	
IN	Indianapolis	0	1	6	7	26
	Evansville	0	1	6	7	
	Fort Wayne	0	1	6	7	
	South Bend	0	0	5	5	
IL	Rockford	0	1	7	8	22
	Champaign	0	1	6	7	
	Peoria	0	0	3	3	
	Springfield	0	1	3	4	
Wi	Milwaukee	0	0	6	6	22
	Madison	0	0	4	4	
	Kenosha	0	1	4	5	
	Green Bay	0	1	6	7	
IA	Des Moines	0	1	6	7	26
	Cedar Rapids	0	1	5	6	
	Sioux City	0	1	5	6	
	Davenport	0	1	6	7	
MO	St Louis	0	1	6	7	27
	St Charles	0	1	6	7	
	St Peters	0	1	6	7	
	O'Fallon	0	0	6	8	
Totals		0	19	135	154	154

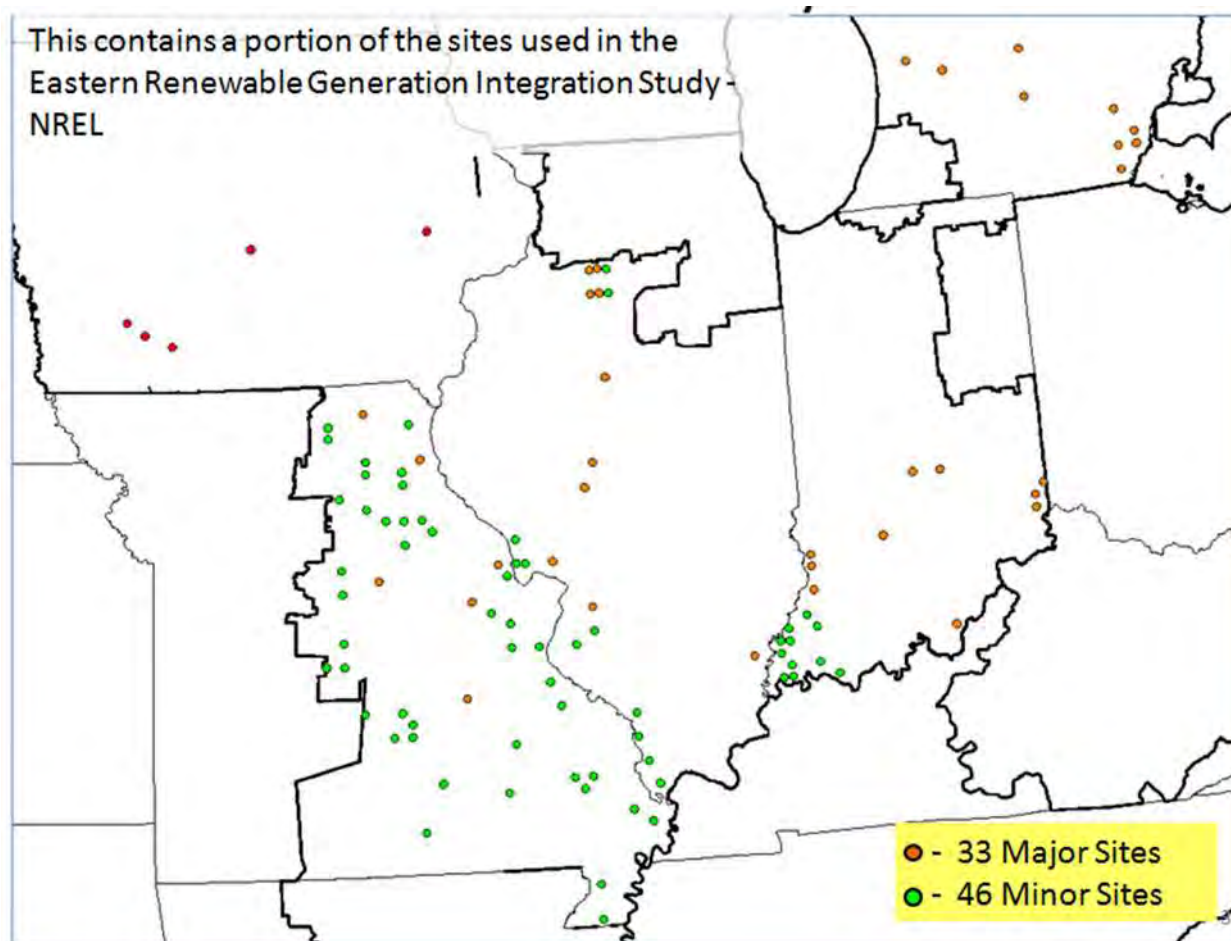


Figure 3-9 Locations of Non-MN Solar - Utility Locations

4 TRANSMISSION SYSTEM CONCEPTUAL PLANS

In 2013, the Minnesota Legislation adopted a requirement that all electrical utilities and transmission companies in the state of Minnesota to conduct an engineering study to evaluate the impacts of raising Renewable Energy Standard (RES) to 40% by the year 2030 and to higher proportions thereafter. This Minnesota Renewable Energy Integration and Transmission Study reviewed the impacts on reliability and costs, including necessary transmission network upgrades, of increasing the RES while maintaining system reliability. As part of this study, Excel Engineering, Inc. was asked to help by performing a Transmission System Conceptual Plan Study. This portion of the study was designed to use powerflow analysis to evaluate certain transmission configurations alongside the production modeling.

4.1 Study Assumptions and Methodology

4.1.1 Study Procedure

The Siemens Power Technologies, Inc. "PSS/E" digital computer powerflow simulation program was used for the steady state thermal analysis to identify the limiting facilities (lines or transformers) which were encountered as the power injection (generation output) was added at the sites of interest per the MRITS Wind-Solar Siting. Beyond the initial load scale-up to configure the models to 2028, the analysis described in this report is based on the "generation to generation" method of modeling new generation resources; consistent with MISO evaluation practice; beyond the initial load scale-up to configure the models to 2028. The "generation to generation" method involves adding new generation and simultaneously backing down or turning off an equal amount of existing generation to keep the system balanced where generation equals load (plus system losses).

A conceptual transmission plan was developed with respect to the Baseline and each scenario. System reliability was determined by technical analyses performed under traditional transmission planning methods, criteria, and assumptions. Performance characteristics to be addressed include the steady-state performance of the following:

Contingency Analysis (powerflow)

- System Intact
- N-1
- Common Structures / Breaker failure (NERC TPL Category C2 & C5)

The local balancing authority areas indicated below were monitored and evaluated for contingency analysis.

Greater than 300 kV

- Wisconsin Electric Power
- ITC Midwest
- MidAmerican Energy Company
- Montana Dakota Utilities
- American Transmission Company

Greater than 200 kV

- Southern Manitoba Area:
 - Facilities South of Winnipeg / Brandon to US border

Greater than 100 kV

- Xcel Energy
- Minnesota Power
- Southern Minnesota Municipal Power Agency
- Great River Energy
- Otter Tail Power
- Western Area Power Administration
- Dairyland Power Cooperative
- ITC Midwest (facilities in Minnesota)
 - Northern Iowa Area: Facilities North of Sioux City / Fort Dodge / Iowa Falls / Waterloo / Dubuque into Minnesota

4.1.2 Models Employed

The study base models used were the 2023 Summer Off-peak (70% load) case and 2023 Summer Peak case from the 2013 MTEP series of models. These models represent the transmission system as it is presently anticipated to be configured in the year 2023. The models were then modified to create a 2028 Baseline model representation with the following additions:

All CapX2020 Group 1 Projects¹

- Monticello-Quarry-Alexandria-Bison (Fargo) 345 kV line
- Brookings Co-Lyon Co-Cedar Mountain-Helena-Chubb Lake (Lake Marion)-Hampton Corner 345 kV, Lyon Co-Hazel Creek 345 kV
- Hampton Corner-North Rochester-North La Crosse 345 kV line
- Wilton-Cass Lake-Boswell 230 kV line

All MISO Multi Value Projects (MVPs) approved in 2011

- Big Stone South-Brookings 345 kV line
- Brookings Co-Lyon Co-Cedar Mountain-Helena-Chubb Lake (Lake Marion)-Hampton Corner 345 kV, Lyon Co-Hazel Creek 345 kV (same as shown in CapX2020 Group 1 Projects)
- Lakefield Jct.-Huntley-Ledyard-Kossuth-O'Brien & Kossuth-Webster 345 kV lines
- Ledyard-Colby-Killdeer-Blackhawk-Hazelton 345 kV line
- Briggs Road-North Madison-Cardinal & Dubuque Co.-Spring Green-Cardinal 345-kV lines
- Ellendale-Big Stone South 345 kV line
- Ottumwa-Adair 345 kV line
- Adair-Maywood-Palmyra 345 kV line
- Palmyra-Maywood-Merlema-Meredosia-Ipava & Meredosia-Pawnee 345 kV lines
- Pawnee-Pana-345 kV Line
- Pana-Mt. Zion-Kansas-Sugar Creek 345 kV line
- Reynolds-Burr Oak-Hiple 345 kV

¹ <http://www.capx2020.com/>, accessed 9/25/2014

- Michigan Thumb Loop Expansion 345 kV line
- Reynolds-Greentown 765 kV line
- Pleasant Prairie-Zion Energy Center 345 kV line
- Fargo-Maple Ridge-Oak Grove 345 kV Line
- Sidney-Rising 345 kV line

Other Transmission Projects

- MTEP Appendix A Projects with In-Service date Prior to 2023
- Manitoba Hydro Bipole III
- Antelope Valley Station-Charlie Creek-Williston-Tioga 345 kV
- Hazleton-Salem 345 kV
- Dorsey-Iron Range 500 kV (Great Northern Transmission Line)
- Increase Square Butte HVDC to 550 MW
- Center - Prairie 345 kV line
- Transmission Owner's transmission changes
 - Winger-Thief River Falls 230 kV line

4.1.2.1 Load Scaling

The load was scaled up in the following areas to get to the 2028 proposed levels.

For Minnesota Utilities

- 0.5% Annually
- 590 MW

For other MISO North and Central Utilities

- 0.75% Annually
- 3460 MW

4.1.2.2 Generation Additions:

The following generation was included: All In-service and/or signed Generator Interconnection Agreements at the start of the analysis.

- Minnesota Power's-Bison Wind 600 MW
- Manitoba Hydro's Keeyask Hydro 695 MW
- Transmission Owner's generation changes

All generation added from the MRITS Wind-Solar Siting were added by the following dispatch criteria of their nameplate value.

Summer Peak Model

- Wind – 20%
- Solar – 60%

Summer Off-Peak Model

- Wind – 90%
- Solar – 60%

The following switched shunt capacitors were added to all models at the following buses for additional voltage support. This was a broad and major addition necessary to build the Baseline model with the load and generation additions to keep the system near 1.0 p.u. voltage, in order to help meet existing MISO North/Central state RPSs.

Switched shunt capacitors were added to all models at the following buses

- 400 MVAR @ Adams 345 kV bus
- 300 MVAR @ Blackhawk 345 kV bus
- 200 MVAR @ Blue Lake 230 kV bus
- 300 MVAR @ Colby 345 kV bus
- 300 MVAR @ Eau Claire 345 kV bus

4.1.3 Baseline Model

The following amounts of generation were added to the MTEP13 2023 models to obtain a Baseline model which meets the current MN RES and other MISO state RPSs.

4.1.3.1 MRITS Wind-Solar Siting

Added beyond MTEP13 2023 models

- Total wind – 6900 MW
- Total Solar – 1509 MW
 - MN Utility PV – 361 MW
 - MN Distributed PV – 96 MW
 - Non-MN Utility PV – 1052 MW
 - Non-MN Distributed PV – 0 MW

Incremental Total – 8409 MW

4.1.4 S1 Model (Added beyond Baseline)

The following amounts of generation were added to the Baseline models to obtain an S1 model which would meet a 40% MN RES standard and existing RPSs in other MISO North/Central states.

4.1.4.1 MRITS Wind-Solar Siting

- Total wind – 1931 MW
 - MN Wind – 1931 MW
 - Non-MN Wind – 0 MW
- Total Solar – 933 MW
 - MN Utility PV – 723 MW
 - MN Distributed PV – 191 MW
 - Non-MN Utility PV – 0 MW
 - Non-MN Distributed PV – 19 MW

Incremental Total – 2864 MW

4.1.5 S2 Model (Added beyond S1)

The following amounts of generation were added to the S1 models to obtain an S2 model which would meet a 50% MN RES standard and a 10% RPS increase in other MISO states.

4.1.5.1 MRITS Wind-Solar Siting

- Total wind – 13636 MW
 - MN Wind – 610 MW
 - Non-MN Wind – 13026 MW
- Total Solar – 6201 MW
 - MN Utility PV – 3840 MW
 - MN Distributed PV – 717 MW
 - Non-MN Utility PV – 3932 MW
 - Non-MN Distributed PV – 154 MW

Incremental Total – 19837 MW

4.2 Results

4.2.1 SCED /MISO Footprint

4.2.1.1 Generation Dispatch Methodology

The models were built while incorporating the wind generation and solar generation within the MISO North and Central footprint. Some wind generation was added using the Security Constrained Economic Dispatch (SCED) which is similar to what is done when MISO creates a base MTEP model and this allows for generation re-dispatch for mitigating overloads. The SCED method determines how the generation resources participating in the market would be dispatched based on economics and reliability where the most cost effective resources are dispatched while maintaining system reliability. This effectively allowed the low-cost wind generation to remain on the system, while other more expensive generation sources are turned down when needed to alleviate congestion. The remainder of the new generation added in the Baseline, S1 and S2 was dispatched in a manner consistent with the MISO Generation Interconnection studies and designated “Footprint Dispatch” and is described as, essentially scaling the whole footprint up and down to keep the swing bus within a certain range after the project under study was added. It is assumed that the swing bus is set based on where it started in the pre-project case.

One of the purposes of the Multi-Value Project (MVP) portfolio was to provide delivery of wind resources needed to meet the MISO state Renewable Portfolio Standards (RPSs). Thus it was decided that for the Baseline case, the 6900 MW (3000+900+3000), deemed the “Multi Value Project wind” and which was required to meet the existing MN RES and other MISO state RPSs, would be dispatched in a SCED methodology and will utilize the MVPs for delivery into the MISO market. Once the Baseline model had been established by using SCED to alleviate constraints, the MISO footprint dispatch methodology was used to offset renewable generation additions in the S1 and S2 scenarios.

4.2.1.2 Baseline

The Baseline models were built incorporating the wind generation of 6900 MW dispatched by Security Constrained Economic Dispatch (SCED) methodology and the solar generation of 1509 MW dispatched across the MISO North and Central footprint. This process first involved adding the 6900 MW of RGOS wind in 20% and 90% (of nameplate) dispatch amounts to the 2028 Summer Peak and Summer Off Peak models respectively and then having MISO run the SCED on these models. Wind plants were modeled at a ± 0.95 power factor at the point of interconnection to the transmission system.

MISO performed the SCED on the models and provided the generation changes for the insertion of 6900 MW of Baseline wind generation. These SCED models were then adjusted by adding 750 MW of new hydro in Manitoba and then dispatching it to WPS (367 MW) and MP (383 MW) along with the 1509 MW of Solar using the "Footprint Dispatch" method which yields the Baseline model. Note: the 367 & 383 MW of hydro add up to 750 MW and are contractual amounts associated with the Great Northern Dorsey to Iron Range 500 kV project.

The following two Baseline models then were created.

S70 -	Summer Off-Peak (70%) Baseline	MRITS2028-S70-R17-Basea.sav
SUM -	Summer Peak Baseline	MRITS2028-SUM-R17-Basea.sav

Figure 4-1 shows how the bus angles for the Off-Peak condition in the Upper Midwest after generation was added from the original 2013 MTEP 2023 model to the Baseline. In examining the bus angle figure, the larger the phase angle difference between points indicates higher power transfers, lower stability margins and more operational issues such as closing in lines after outages, etc.

A very limited number of facilities were overloaded in the Baseline Scenario, so it was determined to be a good starting point for the study. See the Appendix for the full listing (available upon request from GRE).

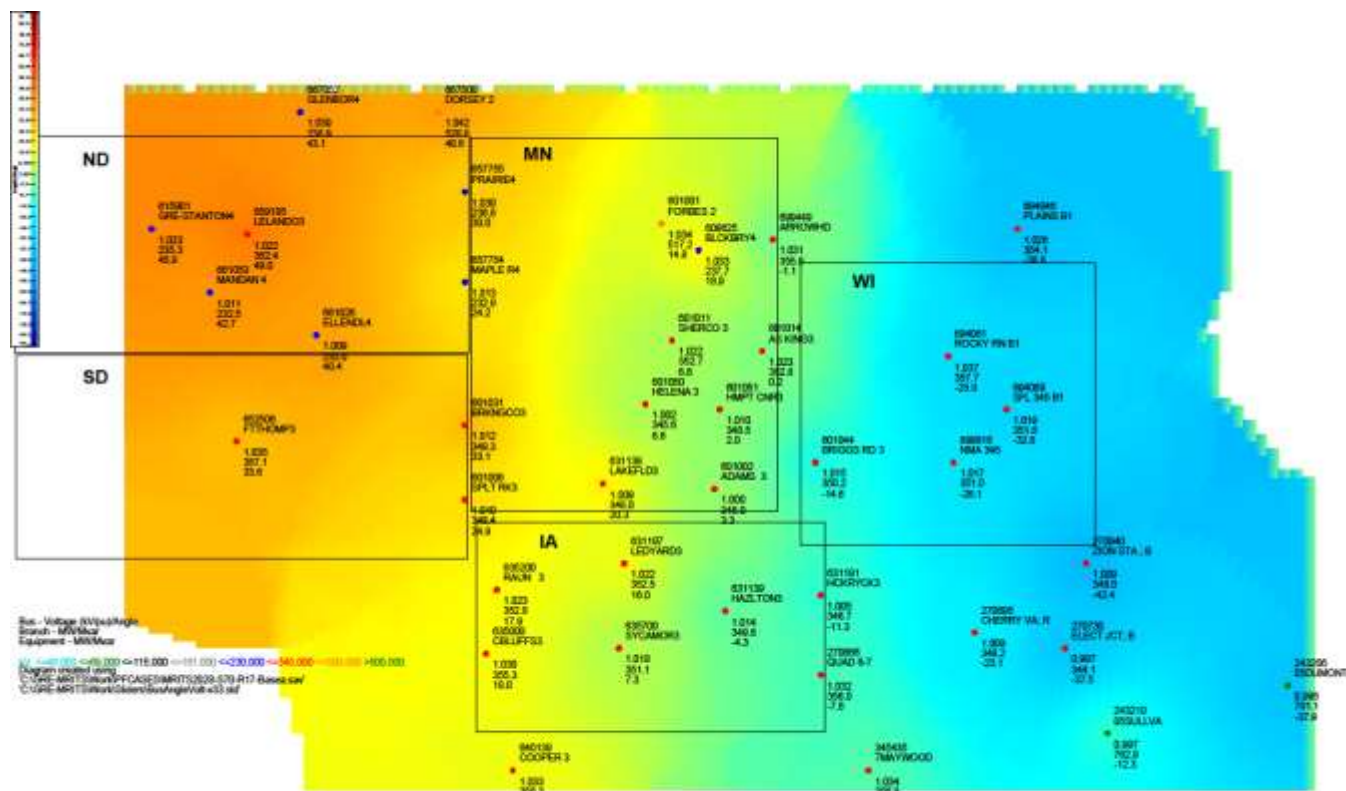


Figure 4-1 Bus Angles from MRITS2028-S70-R17-Basea SCED Model

4.2.1.3 Scenario S1

Similar to some of the generation in Baseline, all of Scenario S1 generation was dispatched to the MISO footprint and the following models were created for S1 Scenario.

S70 -	Summer Off-Peak (70%) S1	MRITS2028-S70-R20-S1.sav
SUM -	Summer Peak S1	MRITS2028-SUM-R20-S1.sav

Figure 4-2 shows how the bus angles change during the Off-Peak condition in the Upper Midwest as the generation was added from Baseline to S1.

As shown in the Bus Angle figure, a bus angle change when moving from Northwest to Southeast is a little more extreme than in the Baseline model.

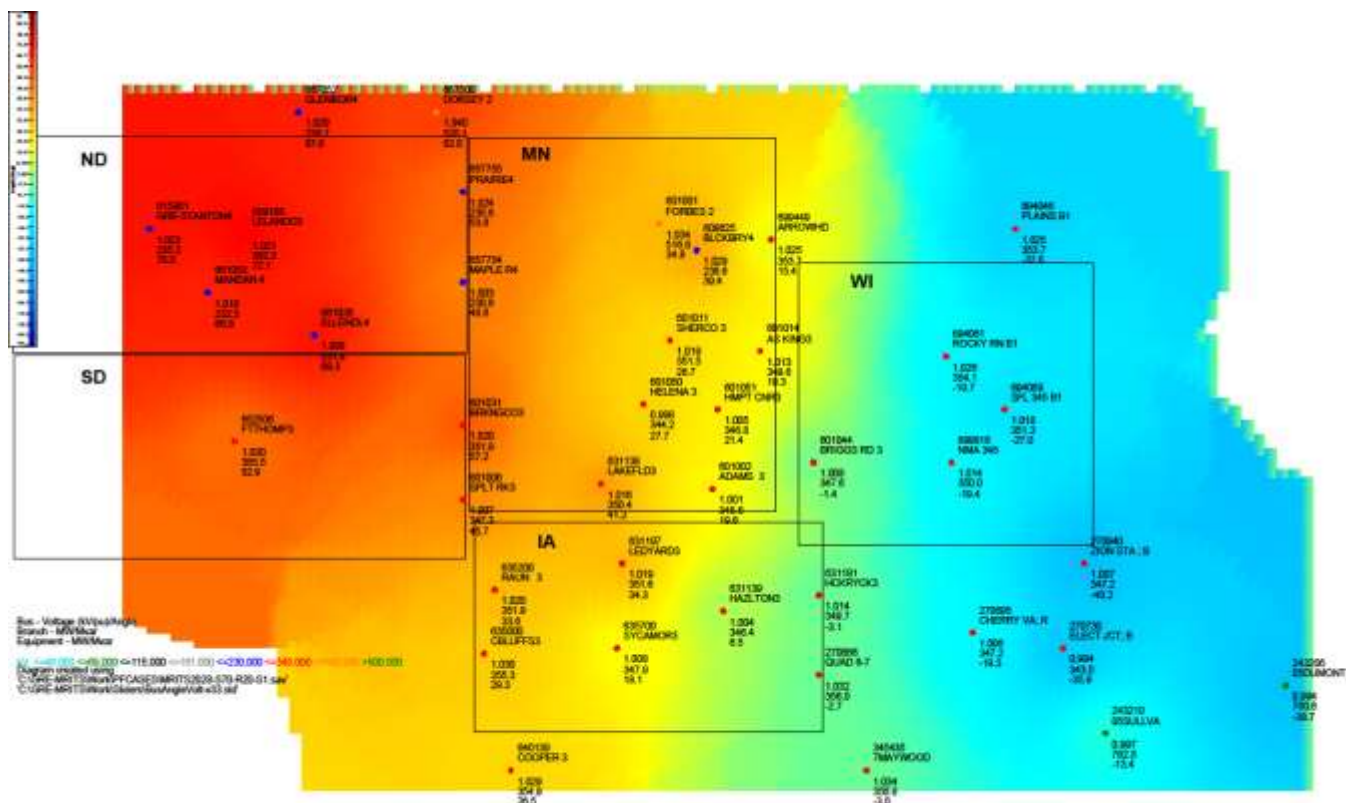


Figure 4-2 Bus Angles from MRITS2028-S70-R20-S1 Model0

Table 4-1 lists mitigation for identified overloads which were required for the S1 Scenario. See Appendices B4 and B6 for the full listing. All costs associated in this report are based on 2014 planning level cost estimates with a $\pm 30\%$ margin of error.

Table 4-1 S1 Transmission Mitigation

Branch	Possible Mitigation	COST (\$M)
Brookings Co-White 345 kV line	WAPA terminal equipment- 1800 MVA	0.50
Cedarsauk-Edgewater 345 kV line	ATC uprate- 750 MVA	1.00
Helena-Scott Co. 345 kV line	XEL rebuild as double circuit	30.00
Ottumwa-Montezuma 345 kV line	ITC uprate- 956 MVA	1.00
Split Rock-White 345 kV line	WAPA terminal equipment- 1195 MVA	1.00
Riverton-Mud Lake 230 kV line	GRE uprate- 383MVA	9.00
98L Tap-Hilltop 230 kV line	MP rebuild - 400 MVA	11.20
Panther-Mcleod 230 kV line	XEL uprate- 391	0.20
Willmar-Granite Falls 230 kV line	GRE rebuild 391MVA	50.00
Hankinson-Wahpeton 230 kV line	OTP uprate- 361 MVA	0.30
Briggs Road-Mayfair 161 kV line	XEL rebuild- 400 MVA	10.00
Drager-Grand Junction 161 kV line	CBPC rebuild- 326 MVA	37.50
Boone Jct-Fort Dodge 161 kV line	MEC / CIPCO rebuild- 326 MVA	62.50
Hazleton-Dundee 161 kV line	ITC terminal equipment- 326 MVA	0.20
Liberty-Dundee 161 kV line	ITC rebuild- 326 MVA	6.50
Wabaco-Rochester 161 kV line	DPC rebuild - 400 MVA	10.90
43L Tap-Laskin 138 kV line	MP rebuild - 200 MVA	3.00
Wilmarth-Swan Lake 115 kV line	XEL terminal equipment- 144 MVA	0.20
Wilmarth-Eastwood 115 kV line	XEL uprate- 310 MVA	3.00
Souris-Velva Tap 115 kV line	XEL terminal equipment- 144 MVA	0.20
Monticello-Oakwood 115 kV line	XEL rebuild- 310 MVA	12.00
Black Dog-Wilson 115 kV line	XEL terminal equipment- 310 MVA	0.20
Chisago-Lindstrom 115 kV line	XEL upgrade- 400 MVA	0.50
Scott Tap-Scott Co. 115 kV line	XEL Rebuild- 310 MVA	2.00
Hassan-Oakwood 115 kV line	XL rebuild- 310 MVA	7.00
Velva Tap-McHenry 115 kV line	XEL terminal equipment- 144 MVA	0.20
Hibbard-Winter St 115 kV line	MP rebuild - 240 MVA	3.00
Etco-Forbes 115 kV line	MP rebuild - 200 MVA	3.00
Forbes-Iron Tap 115 kV line	MP rebuild - 200 MVA	3.00
Hibbing-44L Tap 115 kV line	MP terminal equipment- 80 MVA	0.20

Branch	Possible Mitigation	COST (\$M)
Iron Tap-Tbird 115 kV line	MP rebuild - 200 MVA	3.00
Tbird-37L Tap 115 kV line	MP rebuild - 200 MVA	3.00
Blackberry-Panasa Naswak 115kV	MP upgrade- 240 MVA	2.16
Rugby OTP-Rugby CPC 115 kV line	OTP rebuild - 200 MVA	1.00
Halliday-Beulah 115 kV line	WAPA terminal equipment- 144 MVA	0.20
Rugby-Rugby CPC 115 kV line	BEPC rebuild - 200 MVA	1.00
Johnson Jct-Morris 115 kV line	GRE terminal equipment- 99 MVA	0.20
Johnson Jct-Ortonville 115 kV line	OTP/MRES rebuild - 200 MVA	16.00
Fort Randall-Spencer 115 kV line	WAPA terminal equipment 144 MVA	0.20
Blaisdell-Palermo 115 kV line	BEPC rebuild - 200 MVA	8.00
Logan-SW Minot 115 kV line	BEPC rebuild - 200 MVA	7.00
Hazel Creek 345/230 kV Tx #6	XEL add 2nd 336 MVA transformer	6.00
Stone Lake 345/161 kV Tx #9	XEL replace with 448 MVA transformer	7.50
Eau Claire 345/161 kV Tx #9 & 10	XEL replace BOTH with 448 MVA transformers	15.00
Lyon Co 345/115 kV Tx #1	XEL add 2nd 448 MVA transformer	7.50
McHenry 230/115 kV Tx #1	GRE replace with 187 MVA transformer	2.00
LaCrosse 161/69 kV Tx #1 & 2	XEL replace BOTH with 112 MVA transformers	3.20
Marshland 161/69 kV Tx #1 & 2	XEL replace BOTH with 112 MVA transformers	3.20
Gravel Isle 161/69 kV Tx #5 & 6	XEL replace BOTH with 112 MVA transformers	3.20
West Faribault 115/69 kV Tx #1 & 2	XEL replace BOTH with 140 MVA transformers	3.60
Paynesville 115/69 kV Tx #1 & 2	XEL replace with 70 MVA transformer	2.80
Prentice 115/69 kV Tx #5	XEL replace with 70 MVA transformer	1.40
Holcombe 115/69 kV Tx #1	DPC replace with 70 MVA transformer	1.40
Glendale 115/69 kV Tx #1 & 2	GRE replace Both with 112 MVA BOTH transformers	3.20
	Add breakers at Arrowhead 115kV bus*	2.00

Total Cost 373.06

* To mitigate the contingencies that remove the full 115 kV bus sections, install a breaker-and-half scheme

The map in Figure 4-3 shows all the mitigation required to fix the transmission concerns for dispatching S1 generation to the MISO Footprint. The mitigations are spread throughout the study region.

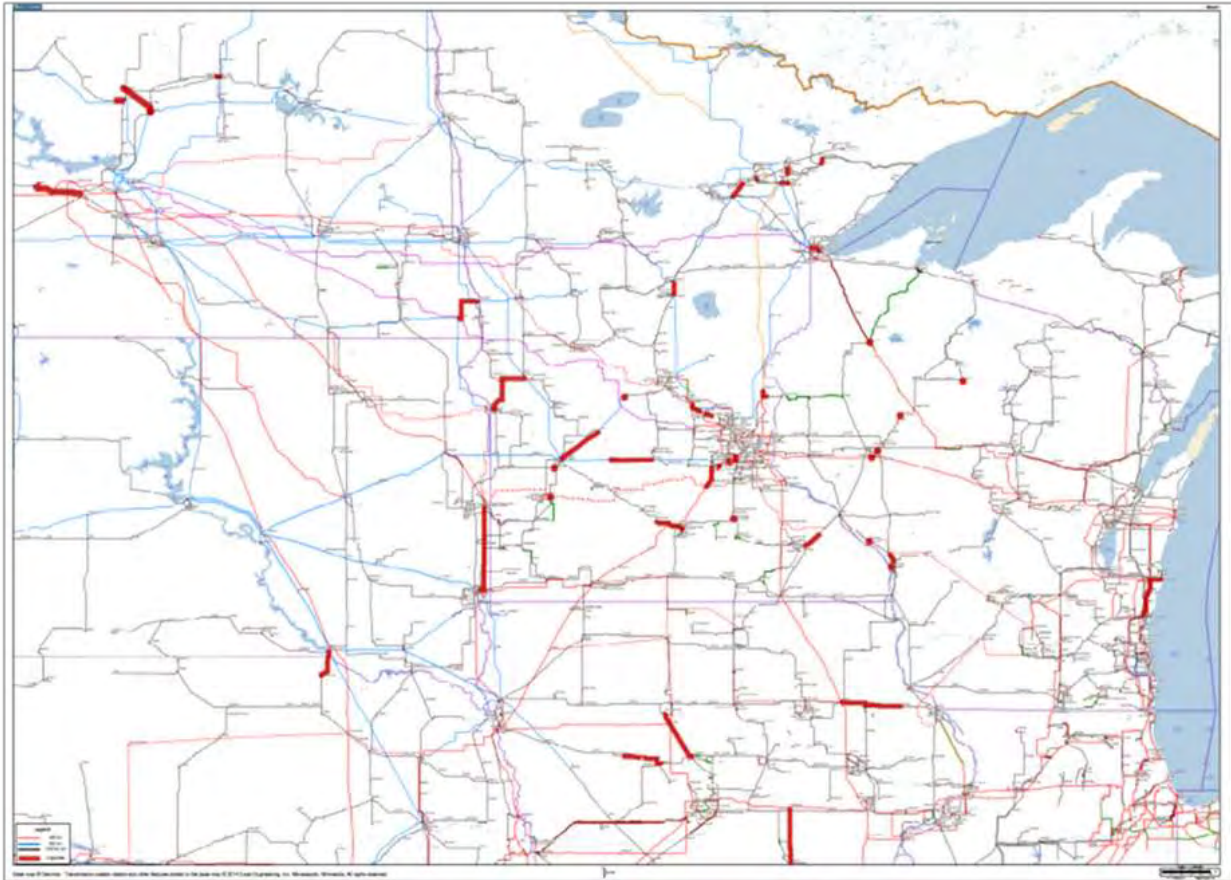


Figure 4-3 S1 Transmission Mitigation Map

The S1 powerflow cases were repeated to verify transmission upgrade results and ensure that the mitigations didn't cause subsequent cascading issue on the system. These mitigations are considered conceptual at this point and thus have not been optimized where, for example, one upgrade or a new facility may alleviate one or more of the identified overloads. Thus, further study would be required for the identification of the most practicable upgrade to alleviate these violations. These 54 mitigations could create a challenge in scheduling and coordinating outages for the construction time necessary to upgrade the facilities.

4.2.1.4 S2 Scenario

The S2 Scenario generation could not be added or dispatched to the MISO footprint similar to Scenario 1 without making some changes and/or additions to the Scenario 1 models primary due to the large amount of renewable generation (17245 MW) being added to the model. The generation addition created an extensive number of violations during system intact conditions along with some extreme contingencies that were difficult to solve.

Figure 4-4 shows an extreme difference in how the bus angles change during the Off-Peak condition in the Upper Midwest as the generation is added from S1 to S2.

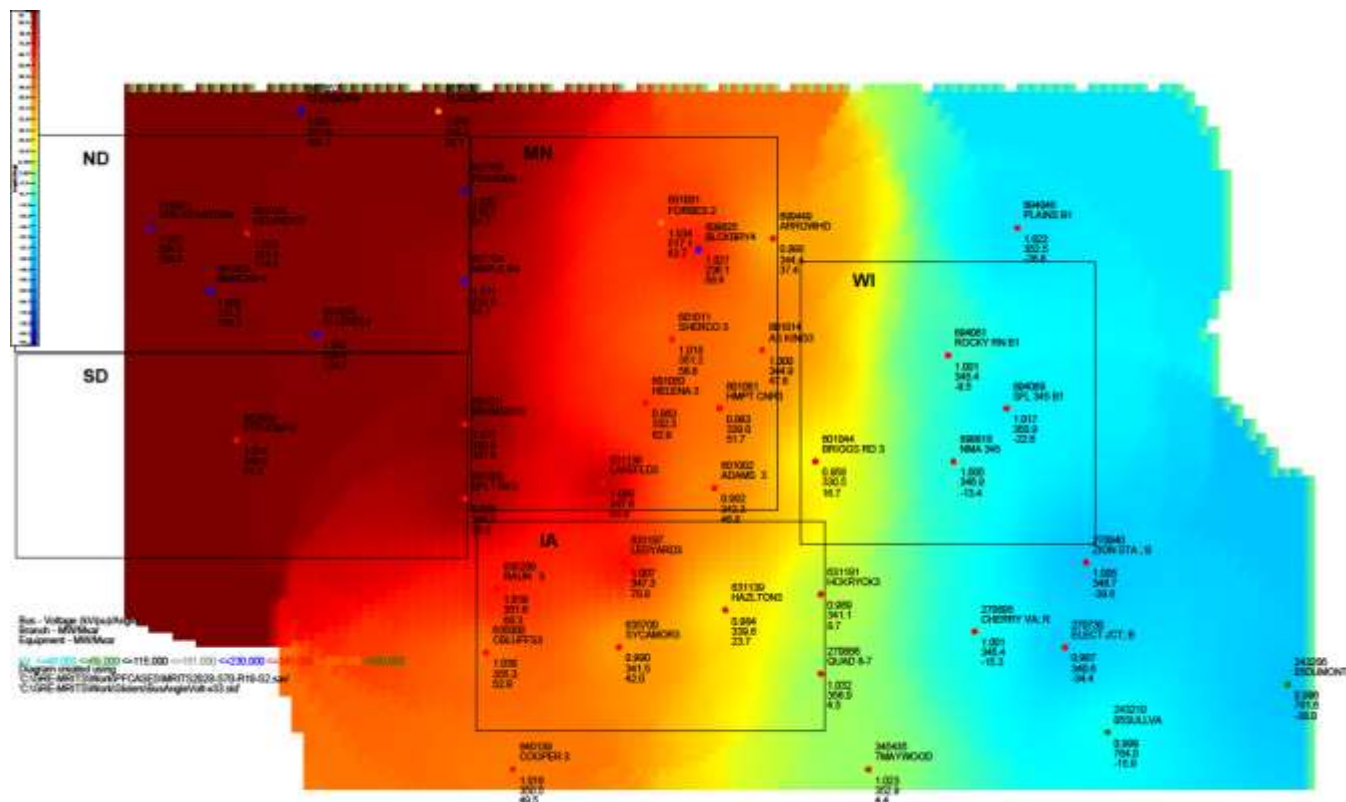


Figure 4-4 Bus Angles from MRITS2028-S70-R19-S2 Model

4.2.2 Scenario 2

4.2.2.1 Transmission Expansion

In order to get the additional \$2 17,245 MW of generation necessary to increase the MN RES to 50% and MISO states collectively to 25% into the case, the transmission expansion projects shown in were included. These expansions are also shown on the map in Figure 4-5.

Figure 4-6 shows how the bus angles change during the Off-Peak condition in the Upper Midwest when added the S2 Transmission Expansion. The change occurs mostly in the area east and southeast of Minnesota.

The cases used with these changes were:

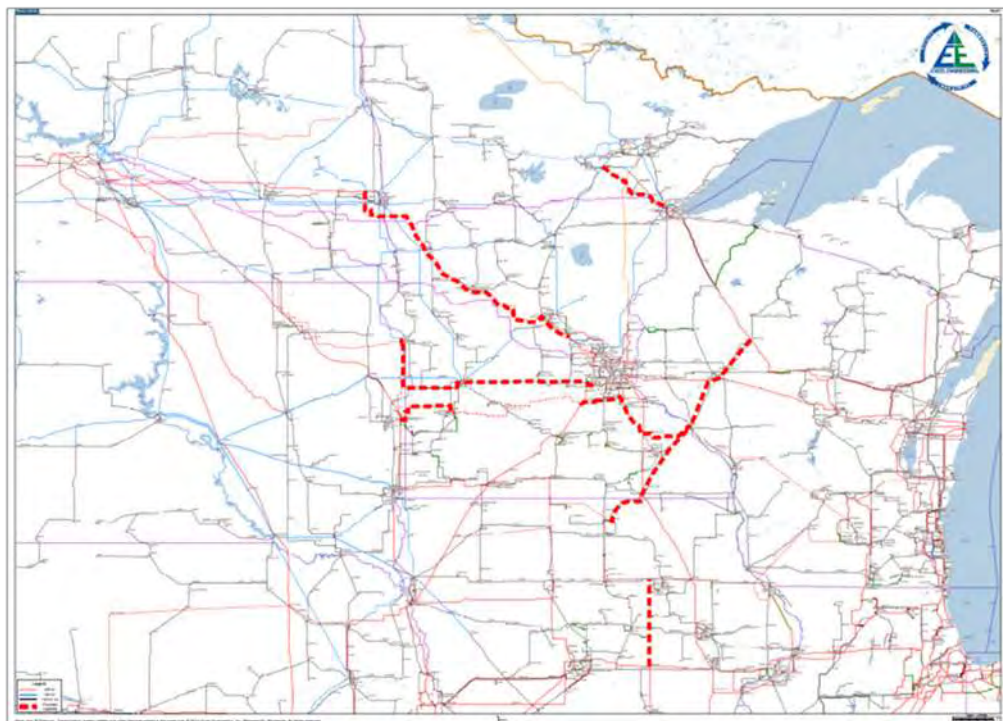
S70 - Summer Off-Peak (70%) S2
SUM - Summer Peak S2

MRITS2028-S70-R19-S2-Trans.sav
MRITS2028-SUM-R19-S2-Trans.sav

Table 4-2 S2 Transmission Expansion

Branch	COST (\$M)
Corridor Project (rebuilding existing 230 kV line to 345 kV) Hazel Creek-Panther-Mcleod-Blue Lake double circuit 345 kV line	466.00
Iron Range-Arrowhead 345 kV line	182.00
Sheldon-Eau Claire-Alma-Adams-Killdeer 345 kV line	700.00
Blackhawk-Montezuma 345 kV line	196.00
Big Stone South-Hazel Creek 345 kV line	200.00
Bison-Alexandria-Quarry-Monticello 345 kV line #2(dbl circuit CapX2020)	204.10
Brookings Co-Lyon Co 345 kV line #2(dbl circuit CapX2020)	58.00
Helena-Chub Lake-Hampton 345 kV line #2(dbl circuit CapX2020)	47.00
Hampton-North Rochester-Alma 345 kV line #2(dbl circuit CapX2020)	75.00

Total Cost \$2,128.10

**Figure 4-5 S2 Transmission Expansion Map**

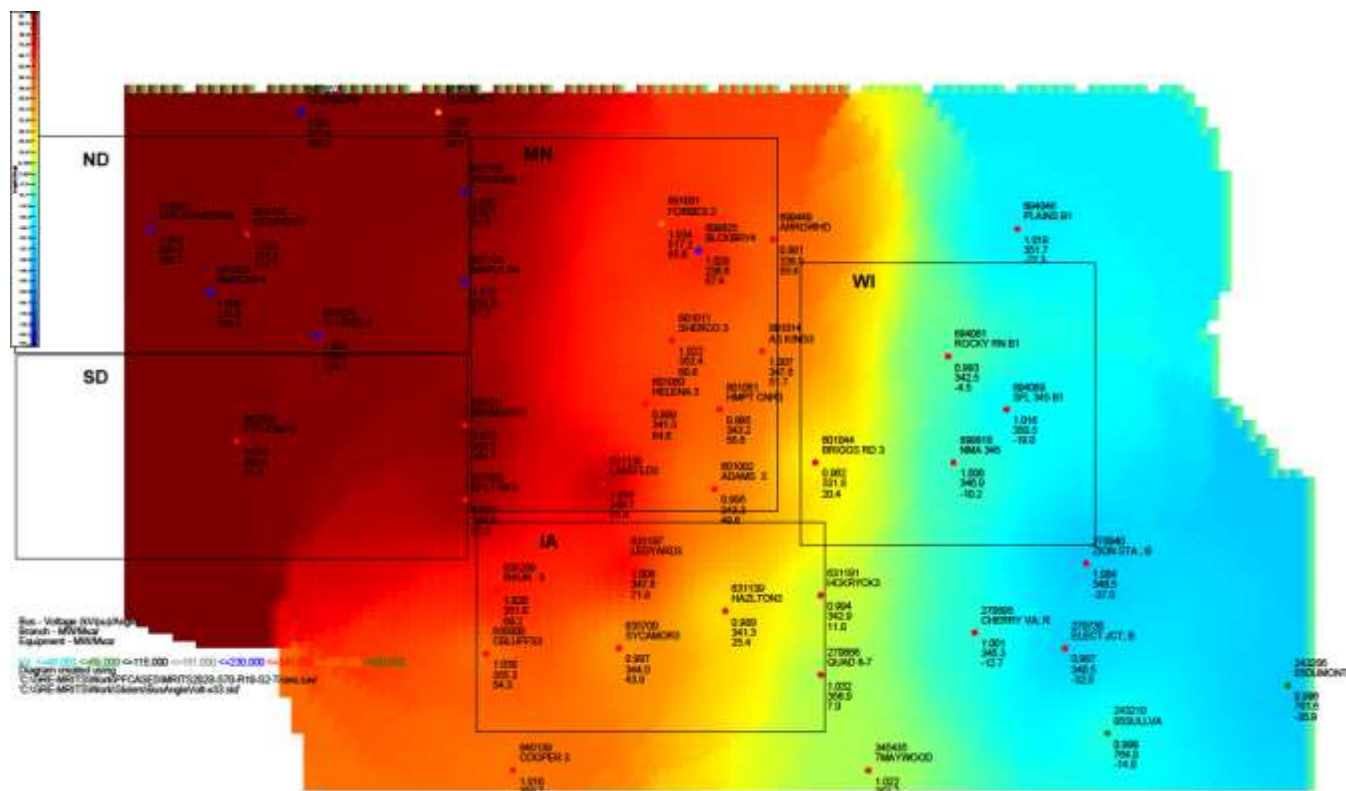


Figure 4-6 Bus Angles from MRITS2028-S70-R19-S2-Trans Model

4.2.2.2 SCED and Top 4 to Bottom 10

Even after the transmission expansion was added to the models, there were still concerns with the amount of equipment overload violations in the model along with some outages not allowing the model to solve. The MRITS task force decided to perform SCED on the S2 cases with the S1 mitigation and the S2 transmission expansion. MISO performed the SCED on models. The cases used for the S2 results were:

S70 -	Summer Off-Peak (70%) S2	MRITS2028-S70-R19-S2-Trans-R2-SCED-A.sav
SUM -	Summer Peak S2	MRITS2028-SUM-R19-S2-Trans-R2-SCED-A.sav

Based on the Production Cost Modeling results, it was noted that several of the wind generation sites from the MRITS Wind-Solar Siting were causing overloads in the thermal case were also congested and thus restricted in the production modeling. The MRITS TRC decided that the top 4 congested non-Minnesota centric generation sites would have generation reduced and moved to the bottom 10 least congested non-Minnesota centric generation sites (T4B10) (as described in the Siting Section). The resulting new S2 cases were:

S70 -	Summer Off-Peak (70%) S2	MRITS2028-S70-R19-S2-Trans-R2-SCED-A-T4B10.sav
SUM -	Summer Peak S2	MRITS2028-SUM-R19-S2-Trans-R2-SCED-A-T4B10.sav

Figure 4-7 shows how the bus angles change during the Off-Peak condition in the Upper Midwest when the S2 Transmission Expansion is added with SCED of S2 generation and the Top4-Bottom10.

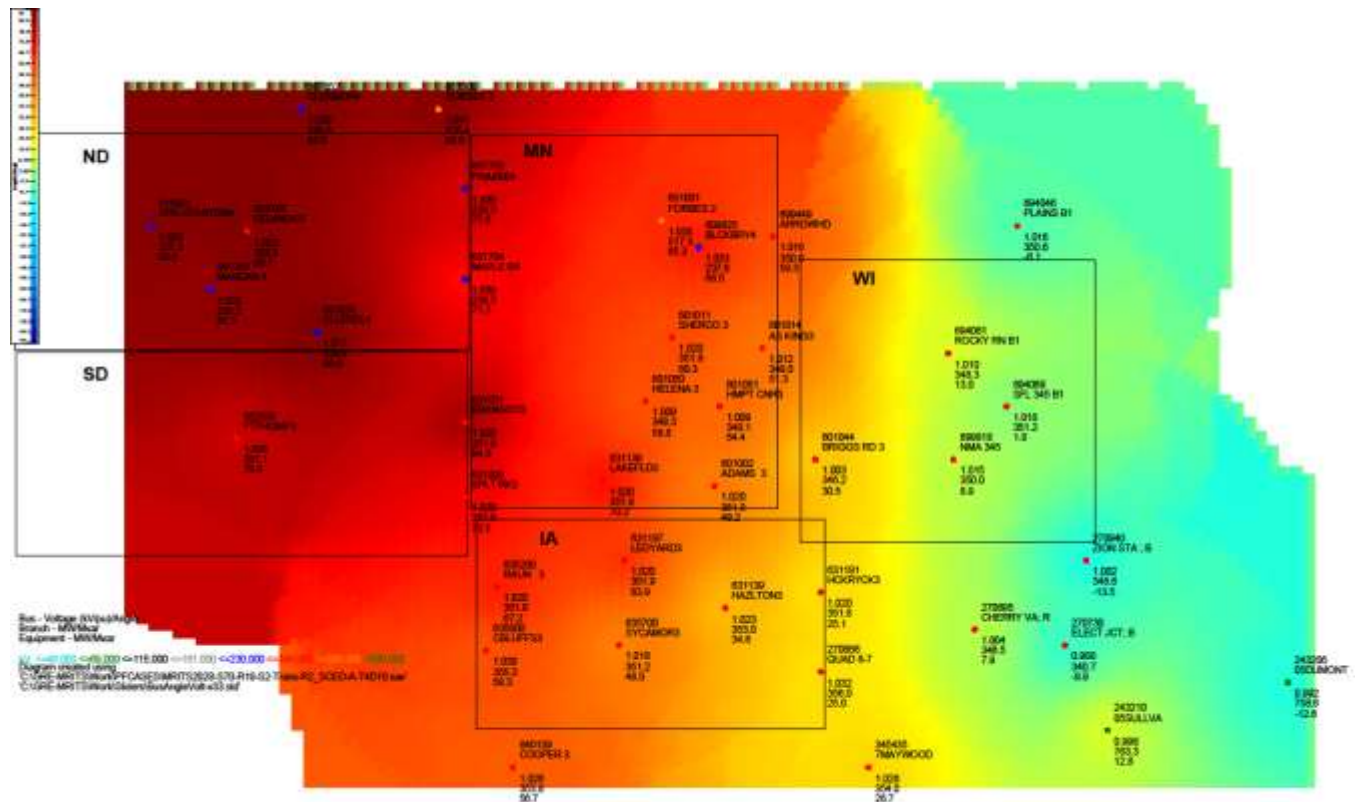


Figure 4-7 Bus Angles from MRITS2028-S70-R19-S2-Trans-R2-SCED-A-T4B10 Model

In addition to the S2 Transmission Expansions (\$2.128B from) and moving some wind generation from the top 4 congested sites to the bottom 10 least congested non-Minnesota centric generation sites, steady state thermal analysis results identified transmission mitigation for the S2. The S2 additional mitigations are shown in Table 4-3. The locations are shown in Figure 4-8. See the Appendix for the full listing (available upon request from GRE).

Table 4-3 S2 Transmission Mitigation

Branch	Possible Mitigation	COST (\$M)
Gardner Park-Sheldon 345 kV line	ATC uprate to 1219 MVA	10.00
Sioux City-Twin Church 230 kV line	NPPD rebuild 390 MVA	37.76
McHenry-Coal Creek Tap 230 kV line	GRE rebuild 450 MVA	78.08
Lakefield-Dickenson Co. 161 kV line	ITC Rebuild 400 MVA	26.75
Triboji-Dickenson Co. 161 kV line	ITC Rebuild 400 MVA	3.00
Huntley-Freeborn 161 kV line	ITC Rebuild 400 MVA	47.88
Webster-Wright 161 kV line	MEC Rebuild 400 MVA	14.75
Alma-Lufkin 161 kV line	DPC Rebuild - 400 MVA	31.50
La Crosse-Mayfair 161 kV line	XEL Rebuild 400 MVA	4.63
Devils Lake-Ramsey 115 kV line	GRE Uprate 120 MVA	0.50
Velva Tap-GRE McHenry 115 kV line	XEL Rebuild 310 MVA	5.20
Souris-Velva Tap 115 kV line	XEL Rebuild 310 MVA	19.60
Sheldon Pump-Osprey 115 kV line	XEL Rebuild 310 MVA	20.90
Osprey-Hawkin 115 kV line	XEL Rebuild 310 MVA	14.00
Hutch McLeod-Hutchinson 3M 115 kV line	GRE Rebuild 310 MVA	5.20
Hutch Muni-Hutchinson 3M 115 kV line	GRE Rebuild 310 MVA	1.10
Sioux City 345/230 kV Tx 1	WAPA replace with a 2x336 MVA transformer	12.00
Stone Lake 345/161 kV Tx 9	XEL modified S1 mitigation, but adding a 2 nd 336 MVA transformer rather than replacing	-
GRE McHenry 230/115 kV Tx #1	GRE replace with 224 MVA transformer	4.00
GRE Spring Creek 161/69 kV Tx #2	GRE replace BOTH with 112 MVA transformers	3.20
Prairie 115/69 kV Tx #2	MPC add 69 kV breakers	2.00
GRE St. Boni 115/69 kV Tx #1	GRE replace with 112 MVA transformer	1.60
Split Rock 345/115 kV Tx # 11	XEL add 3rd 448 MVA transformer	7.50

Total Cost 351.14

As seen in Figure 4-8, the mitigations are spread throughout the study region and there is a recognition that there may have been more system overloads outside the study monitor area.

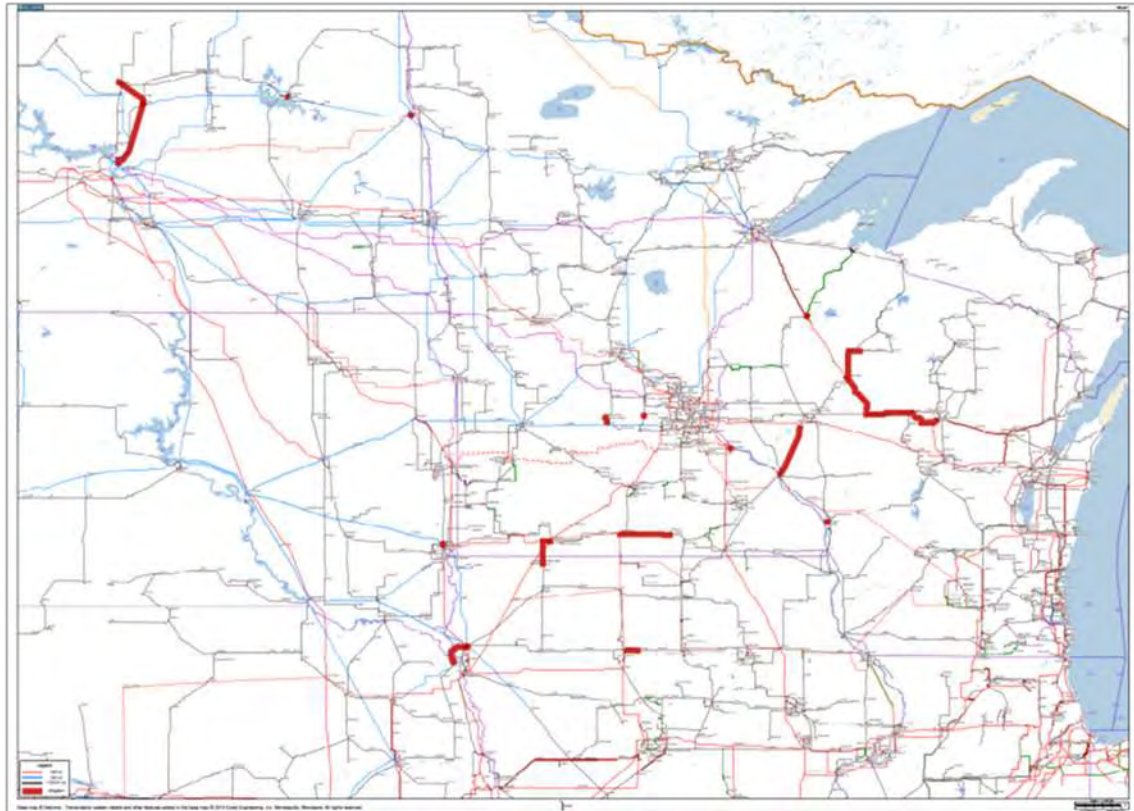


Figure 4-8 Transmission Mitigation Map

The S2 powerflow cases were repeated to verify transmission upgrade results. The transmission expansions and mitigations are considered high-level and conceptual at this point and thus have not been intensively analyzed and compared with other alternative mitigations nor have the projects been optimized where, for example, one upgrade or a new facility may alleviate one or more of the identified overloads.

Thus, further study would be required for the identification of the most practicable expansion or upgrade to alleviate these specific violations or widespread grid issues. These upgrades would require coordination with study and validation by MISO and other utilities. These 9 expansions and 23 mitigations could create a challenge in scheduling and coordinating outages for the construction time necessary to upgrade and build the facilities.

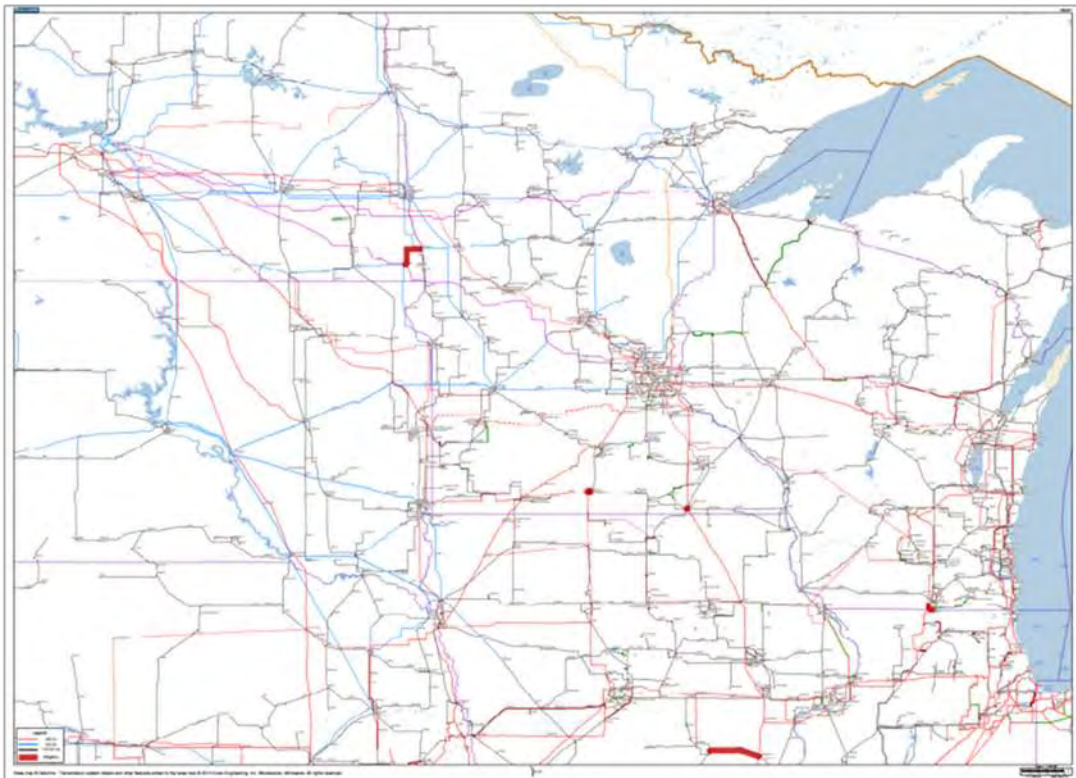
4.2.2.3 Production Cost Mitigation

Following the steady state power flow modeling which produced the transmission expansions and mitigations, Production Cost Modeling was performed to determine if any additional transmission facilities should be upgrades to help alleviate market congestion. This generation siting shift assisted in producing a more reliable and efficient market system. Table 4-4 lists mitigations from the production cost analysis. See the Appendix for the full listing (available upon request from GRE).

Table 4-4 S2 Transmission Mitigations from Production Cost Analysis

Branch	Possible Mitigation	COST (\$M)
Blackhawk SW Yd-Colley Rd 138 kV line	ATC Rebuild- 400 MVA	1.95
Adams 161/69 kV Tx #1 112MVA	ITC replace with 112 MVA transformer	1.60
Huntley (Winnebago) 161/69 kV Tx #1 70 MVA	ITC replace with 70 MVA transformer	1.40
NW Beloit-Paddock 138 kV line	ATC Rebuild- 400 MVA	3.15
Hankinson-Wahpeton 230 kV line	OTP Rebuild- 430 MVA	40.80
Wapello Co.-Jeff 161 kV line	ITC Rebuild- 400 MVA	33.90
Blue Earth Tap-Huntley (Winnebago) 161 kV line	ITC Rebuild- 400 MVA	5.25

Total Cost 88.05

**Figure 4-9 Map of S2 Transmission Mitigations from Production Cost Analysis**

4.2.2.4 HVDC Transmission

Given the large number and magnitude of 345 kV mitigations identified for Scenario 2, it was decided to conduct a mitigation sensitivity using a HVDC design to deliver the non-MN MISO wind located in western MISO to eastern MISO. This HVDC multi-terminal line design was guided by Bus Angles shown in Figure 4-4 in order to connect the HVDC terminals to the extreme angle differences (Red and Blue). The HVDC line was approximately 800 miles long and operated at 600 kVdc with two converter buses located at Brookings County and O'Brien County and two inverter buses located Breed (Sullivan) and Dumont.

All runs were done only on the off-peak (S70) case and were not optimized in any form, but to be used as a reference. The line was tested at 2000, 2500, 3000 and 3500 MW. The cases used in the review were:

2000 MW	MRITS2028-S70-R19-S2-HVDC-2000.sav
2500 MW	MRITS2028-S70-R19-S2-HVDC-2500.sav
3000 MW	MRITS2028-S70-R19-S2-HVDC-3000.sav
3500 MW	MRITS2028-S70-R19-S2-HVDC-3500.sav

Figure 4-10 is a map showing the HVDC line location and the four terminals (red dots).

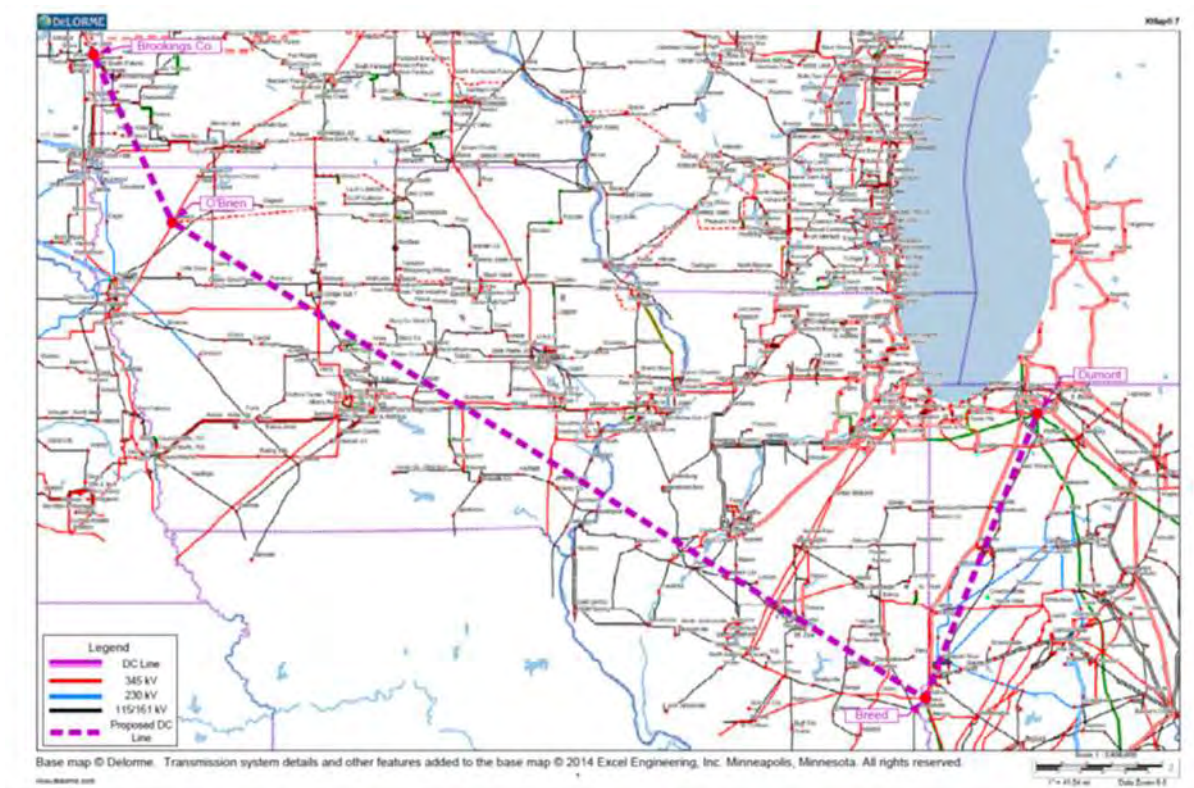


Figure 4-10 HVDC Transmission Map

The HVDC line transferred a significant amount of power from the converter terminals in the west, where a major amount of the MRITS Wind-Solar Siting were located at or near those terminals. If future wind would be developed further away from the HVDC terminals, the HVDC Transmission Expansion option would not be as efficient at transferring power from Western MISO to Eastern MISO and other transmission upgrades would likely be needed to get the new wind to the HVDC terminals. Contingency or Outage of the HVDC line as full, two-pole, or partial, single pole was not evaluated during this study. These outages would require an extensive study and thus was not conducted. We do know from previous work in this study that the ac transmission system could not accommodate all the S2 generation without some additional transmission, so some level of generation runback/tripping or ac transmission expansion would be required in the case of a single or double pole HVDC outage. The estimated cost for a four terminal 3500 MW HVDC for this distance would be approximately \$3 Billion. See the Appendix for the full listing (available from GRE upon request).

An undetermined portion of the HVDC estimated cost could be allocated to central and eastern portions of MISO to help meet their respective RPSs.

Table 4-5 lists the ac transmission mitigation required beyond S1 mitigation and the HVDC at 3500 MW. This is an increase in \$280M of mitigation beyond the S1 mitigations. This table does not include mitigations for the outage of the HVDC.

Table 4-5 S2 AC Transmission Mitigations required with HVDC Option

Branch Violation	Contingency	COST (\$M)
Hazelton-Mitchell Co. 345 kV line	ITC/ MEC Upgrade- 1464 MVA	201.60
McHenry-Coal Creek Tap 230 kV line	GRE upgrade- 637 MVA	78.08
McHenry-Balta 230 kV line	GRE upgrade- 480 MVA	69.44
Big Stone-Big Stone South 230 kV line	OTP upgrade- 831 MVA	5.00
Oakes-Ellendale 230 kV line	OTP upgrade- 480 MVA	38.40
Blair-Watertown 230 kV line	WAPA upgrade- 480 MVA	46.40
Briggs Road-Mayfair 161 kV line	XEL upgrade- 434 MVA	10.00
Lacrosse-Mayfair 161 kV line	XEL upgrade- 434 MVA	4.63
Wheaton-Elk Mound 161 kV line	XEL upgrade-434 MVA	4.50
Beaver Creek-Adams 161 kV line	DPC upgrade- 434 MVA	18.88
Wabacco-Alma 161 kV line	DPC upgrade- 434 MVA	25.38
Swan Lake-Fort Ridgely 11 kV line 5	XEL upgrade- 232 MVA	13.20
Franklin-Redwood Falls 115 kV line	XEL upgrade- 232 MVA	12.80
MN Valley-Redwood Falls 115 kV line	XEL upgrade- 232 MVA	27.80
Lawrence Creek-Shafter 115 kV line	XEL upgrade- 350 MVA	6.10
Lindstrom-Shafer 115 kV line	XEL upgrade- 319 MVA	2.80
Big Stone-Highway 12 115 kV line	OTP upgrade- 319 MVA	2.00
Highway 12-Ortonville 115 kV line	OTP upgrade- 319 MVA	4.50
Hoot Lake-Fergus Falls 115 kV line	OTP upgrade- 232 MVA	4.20
OTP Forman-WAPA Forman 115 kV line	OTP upgrade- 232 MVA	0.20
Devils Lake SE-Ramsey 115 kV line	OTP upgrade- 232 MVA	0.20
Aberdeen Jct-Ellendale 115 kV line	NWE upgrade- 232 MVA	39.00
Iron Range 500/230 Tx	MP upgrade- 1043 MVA	0.00
Forman 230/115 Tx	WAPA replace w/ 180 MVA transformer	2.00
Big Stone South 345/230 Tx #1 & 2	OTP replace BOTH w/ 800 MVA transformer	15.00
Big Stone South 230/115 Tx	OTP replace with 390 MVA transformer	6.00

Total Cost 630.60

4.3 Conceptual Transmission Conclusions

The model building for the steady state thermal analysis involved significant transmission and generation additions and load increases to reflect the Baseline assumptions of the present MISO state RPSs in a 2028-2030 timeframe along with the planned transmission and generation build-outs.

The generation dispatch involved a combination of methodologies to best represent the future system grid which accommodated the lowest fuel cost generation units and future contracts while maintaining system reliability.

The Scenario 1 Transmission Mitigations, as identified with steady state thermal powerflow analysis, to accommodate an increase wind and solar generation necessary to increase the MN RES to 40% involved 54 facilities with a total estimated cost of \$373M.

The Scenario 1 mitigations are considered conceptual at this point and thus have not been optimized and thus further study would be required for the upgrading/mitigation of these violations. These 54 mitigations could create a challenge in scheduling and coordinating outages for the construction time necessary to upgrade the facilities.

To reliably accommodate the addition of 17,245 MW of Scenario 2 generation necessary to increase the MN RES to 50% and MISO states collectively to 25% into the case and alleviate widespread system issues, a significant amount of transmission expansions were identified and included in the S2 models. These expansions involved 9 facilities with a total estimated cost of \$2,128M.

Even with the S2 expansions identified above, there were still concerns with the high number of facility overloads and violations, it was noted that several of the wind generation sites from the MRITS Wind-Solar Siting were causing market congestion and it was decided that the top 4 congested non-Minnesota centric generation sites would have generation reduced and moved to the bottom 10 least congested non-Minnesota centric generation sites (T4B10). This generation siting shift assisted in producing a more reliable and efficient market system.

In addition to the S2 Expansions and moving some wind generation from the top 4 congested sites to the bottom 10 least congested non-Minnesota centric generation sites, steady state thermal powerflow analysis still identified Scenario 2 Transmission Mitigations, involving 23 facilities with a total estimated cost of \$351M.

The Production Cost Modeling & Analysis showed market congestion caused by the overload of several facilities. These congestion points in the MN Centric area were selected for mitigation and these involved 7 facilities with a total estimated cost of \$88M.

The total Scenario 2 expansions and upgrades involved 39 projects at an estimated cost of \$2,567M. The cost of the Scenario 1 mitigations should be added to the S2 costs in order to accommodate a MN RES of 50% and a MISO collective RPS of 25%. It should be noted that an undetermined portion the S2 transmission expansions and upgrades are likely due to the non-MN MISO renewables and not exclusively for the MN renewables. No effort was made to separate these costs into those assigned to MN Renewables and those to non-MN MISO renewables.

Table 4-6 Scenario Transmission Cost Breakdown

	Expansion Costs (\$M)	Mitigation Costs (\$M)	Market Mitigation Costs (\$M)	Total Costs (\$M)
Scenario 1	\$0	\$373	\$0	\$373
Scenario 2	\$2,128	\$351	\$88	\$2,567

An alternative to the above expansions and mitigations, a high level HVDC line was tested as a sensitivity. The modeled 600 kV HVDC line was about 800 miles long and with converter buses located at southeastern South Dakota and northwest Iowa and two inverter buses located northern and southern Indiana. The estimated cost of this HVDC project was approximately \$3B and still required 26 mitigations with an estimate cost of approximately \$631M for a total HVDC portfolio cost of approximately \$3.6B, which is approximately a 40% increase over the ac mitigation portfolio).

The transmission expansions and mitigations are considered high-level and conceptual at this point and thus have not been intensively analyzed nor optimized thus, further study would be required for the identification of the most practicable expansion or upgrade and would likely change as the wind is actually developed. These upgrades would require coordination with MISO and other utilities. These transmission expansions and mitigations could create a challenge in scheduling and coordinating outages for the construction time necessary to upgrade and build the facilities.

This study builds upon several previous state mandated renewable related studies and the analysis and results have demonstrated the regional nature and benefits of the grid and the operating market.

5 DYNAMIC SIMULATION MODEL

This section documents the data source for the dynamic modeling, benchmarking of the model, modifications made to represent the future high-renewable scenarios and criteria for evaluating stability simulations.

5.1 Data Sources and Benchmarking of Dynamic Models

The original data for dynamic analysis provided by the Minnesota utilities was based on an MTEP 2013 data set. The following files were provided:

Powerflow data in PSS/E raw data format: *2023_SH_2013DPP_August_Pre-DPP.raw*

Case comments:

2023 SHOULDER LOAD CASE

AUG 2013 DPP BASE CASE, PRE DPP

Dynamic data in PSS/E dyre data format: 2018_final_2.dyr

Contingency description files provided in PSS/E response file (.idv) format

These files were converted to GE PSLF format and tested by simulating the benchmark contingencies listed in Table 5-1. Simulations were compared to results obtained using a similar database in PSS/E. Simulation results were reviewed with the MRITS Technical Team. After some minor modifications to the dynamic data (adding mechanically switched capacitor models), the benchmarking results were deemed acceptable.

Note that the PSLF model does not include custom HVDC controls. Rather, it represents a typical HVDC system. Simulation results were reviewed by Technical Team members to ensure that the simulated HVDC response represented expected response. In particular, commutation failure and blocking was reviewed for disturbances near the HVDC terminals.

Table 5-1 Benchmark Contingencies

Name	Description
EI2	CU HVDC Permanent Bipole fault with tripping of both Coal Creek units.
AG1	SLG fault with breaker fail at Leland Olds on the Ft. Thompson 345 kV line
AG3	3 phase fault at Leland Olds on Ft. Thompson 345 kV line, Clear both ends of the line in 4 cycles
NAD	4cycles 3 phase fault on the Dorsey to Forbes 500 kV line D602F at Forbes. Runback bi-poles that terminate at Dorsey
PCS	SLG fault t with breaker fail at King with 8P6 stuck. Trips King-EauClaire-Arpin and King-Chisago 345 kV line

5.2 Dynamic Load Model

After obtaining acceptable benchmarking results, the dynamic data set was modified to include a more detailed representation of the study area loads. The objective of adding a dynamic load model was to capture possible fault-induced delayed voltage recovery issues caused by reduced synchronous generation.

The GE PSLF composite load model CMPLDW was added at all loads greater than 5 MW throughout MISO. The topology of the composite load (shown in Figure 5-1) is intended to give more realistic representation of dynamic load behavior than present practice. The model adds distribution transformer and feeder for each load. The load is then modeled at the distribution bus as a composite of different induction motors, electronic load and static load.

In order to develop parameters for the load model, the Minnesota utilities classified all loads in their service territory. Classifications for non-industrial loads are shown in Table 5-2. Classifications for industrial loads are shown in Table 5-3. Loads not identified by the Minnesota utility were assumed to be either power mixed residential/commercial, or power plant auxiliary. Power plant auxiliary loads were assumed if the load was at a generator bus with a rated voltage less than 30 kV.

The load characteristics used for each individual load were based on the load type using the WECC parameters. In total, the CMPLDW model was added to 2045 loads (37.8 GW for the shoulder period). Note that a different set of parameters was used for the light and shoulder load cases and the peak load case. This was intended to represent the higher level of motor load, particularly air conditioning, during the summer peak load than during spring and fall.

The parameters of the four equivalent motors are particularly important for dynamics, as the tendency for motor groups to stall (or not) during major voltage depressions has a substantial impact on system stability. One of the key features of the composite load model includes the ability to control whether stalled motors trip (by contactors opening) or continue to stay attached drawing starting current. Since the motor stalling behavior in the composite load has such a major and acutely non-linear effect on stability results, for this study, all motor tripping in the composite model is disabled. This is very conservative, and it allows for simpler and more illuminating comparison between dynamic simulation cases.

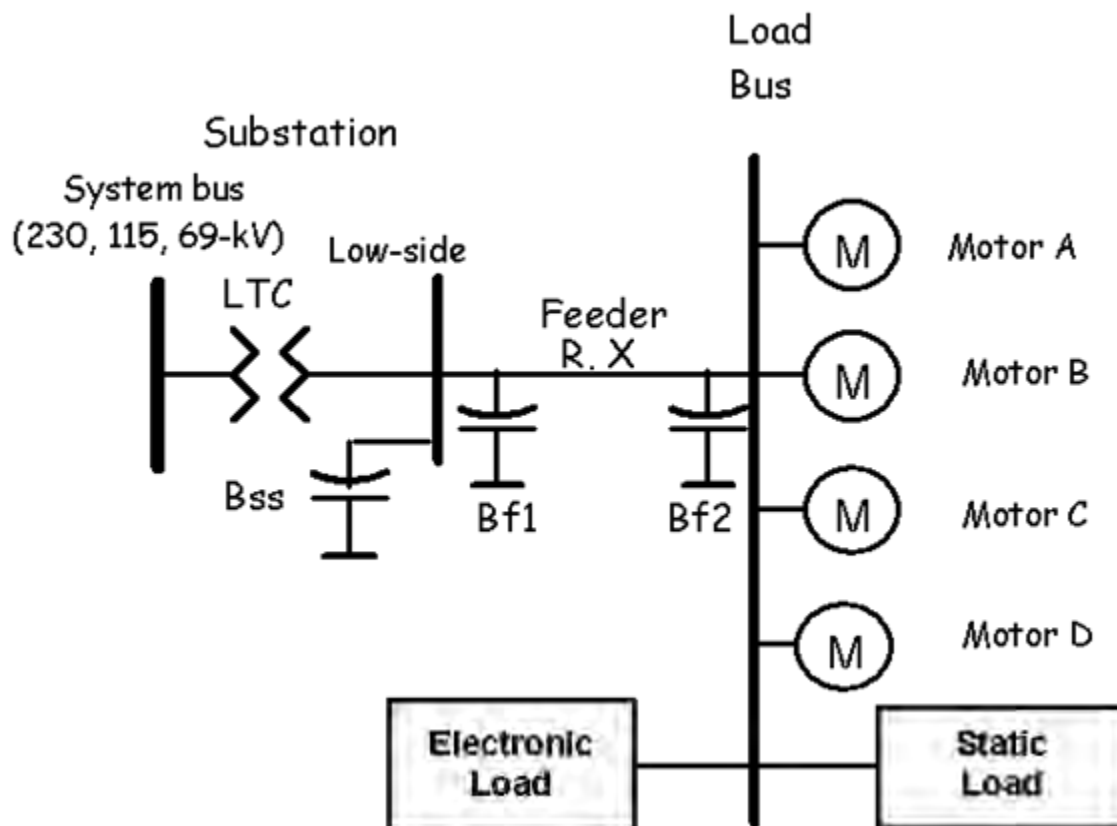


Figure 5-1 GE PSLF Composite Load Model CMPLDW

Table 5-2 Non-industrial Load Types

ID	Feeder Type	Residential	Commercial	Industrial	Agricultural
RES	Residential	70 to 85%	15 to 30%	0%	0%
COM	Commercial	10 to 20%	80 to 90%	0%	0%
MIX	Mixed	40 to 60%	40 to 60%	0 to 20%	0%
RAG	Rural	40%	30%	10%	20%

Table 5-3 Industrial Load Types

ID	Feeder Type
IND_PCH	Petro-Chemical Plant
IND_PMK	Paper Mill – Kraft process
IND_PMT	Paper Mill – Thermo-mechanical process
IND_ASM	Aluminum Smelter
IND_SML	Steel Mill
IND_MIN	Mining operation
IND_SCD	Semiconductor Plant
IND_SRF	Server Farm
IND_OTH	Industrial – Other
AGR_IRR	Agricultural irrigation loads
AGR_PMP	Large pumping stations with synchronous motors
PPA_AUX	Power Plant Auxiliary

5.3 2028 Study Data Sets

The original MTEP data set represented a 2023 shoulder load condition. This data set was modified to establish the 2028 light load, shoulder load and peak load cases. This involved adjusting the load in the MISO areas appropriately to represent 2028 conditions and adding the conceptual transmission plans identified in the thermal and voltage analysis. In going from shoulder load 2023 to 2028, a 0.5% annual load growth was assumed for Minnesota and 0.75% annual load growth was assumed for rest of the MISO. The load in the 2028 shoulder case was then modified to develop a 2028 light load and 2028 peak load case. The new wind and solar generation for each scenario (baseline, S1 and S2) were then added to the 2028 cases.

5.4 Dynamic Models for Renewables

The powerflow topology was modified to interconnect the new wind and utility-scale PV plants and distributed PV. These new plants have two transformations, one for the substation transformer and an equivalent for the unit transformer (from collector voltage to inverter voltage) with an intervening equivalent of the collector system. The arrangement is shown in Figure 5-2.

For dynamic modeling, the utility-scale PV plants are modeled with full four quadrant dynamic models (based on the Type 4 wind turbine generator [WTG] model) with voltage regulation and zero-voltage ride-through (ZVRT). The utility-scale PV plants are modeled with a power factor of ± 0.90 at the inverter transformer. This gives an MVA rating of 1.11 times the plant MW rating, and reactive capability of ± 0.436 pu, based on the MVA rating. New wind plants were split roughly 50/50 between Type 3 double fed asynchronous generator (DFAG) and Type 4 (full converter) with voltage regulation and ZVRT. The new wind plants are modeled with a power factor of ± 0.90 at the 690V

bus. This gives an MVA rating of 1.11 times the plant MW rating, and reactive capability of ± 0.436 pu, based on the MVA rating. Both wind and utility-scale PV were set to regulate the 690 V terminal bus. Although advanced WTG controls such as inertial response and frequency response were available in the models, they were assumed to be inactive. Furthermore, they were not required for mitigation during the dynamic analysis task.

Distributed PV was modeled as lumped generation in central locations, based on the siting work. The distributed PV was modeled with no reactive/voltage regulation capability. The ability of the distributed PV generation (DPV) to ride through voltage and frequency excursions is handled by a separate logic. The model allows selection of different levels of voltage and frequency excursion that will result in the DPV blocking. A further part of the logic allows specification of how much DPV will recover if the excursion returns within the user input bounds. The result is a high level of flexibility for modeling fault ride-through. However, the model does not support user input time delays on the blocking functions, and so is limited in its ability to reflect deliberate time thresholds for tripping (e.g., of the type in NERC low voltage ride through (LVRT) and IEEE 1547 standards).

Voltage ride through settings used for the DPV maintained full PV output between 0.90 pu and 1.10 pu voltage. Between 0.90 pu and 0.88 pu voltage, the DPV active power is run back linearly to zero. Below 0.88 pu voltage the PV is blocked. When voltage recovers above 0.9 pu the active power is restored. Similar logic is used for high voltage conditions between 1.1 and 1.2 pu.

Frequency ride through/blocking was modeled similar to voltage ride through/blocking. The DPV retains full output between 59.70 Hz and 60.30 Hz. Between 59.70 Hz and 59.50 Hz the DPV active power runs back and is fully blocked below 59.5 Hz. However, unlike the voltage ride-through function, the PV active power does not recover after being blocked due to high or low frequency. There were no time delays model for the voltage or frequency ride through/blocking logic.

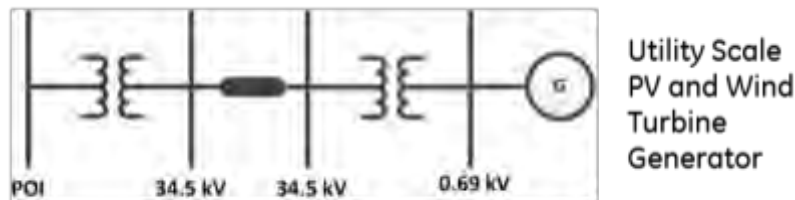


Figure 5-2 Renewable generation topology in powerflow Model

5.5 Monitoring Models and Performance Metrics

In order to quantify the effect of increased renewable generation on the system performance, several sets of metrics are developed. The metrics are geared towards identifying first swing stability, power swing damping and voltage response and recovery following a fault. Rotor angle of generators in the entire Eastern Interconnect are monitored to ensure if the system is transiently stable following each disturbance. Voltages are monitored for 220 kV and above buses throughout MISO.

In addition, a region-wide monitoring approach is used to identify issues that are not apparent from traditional stability plots. In this regard, a new dynamic model is developed to monitor regional performance. Regional metrics include measures such as, total rated MVA, rated MW, actual MW

and MVAR and reactive reserves for on-line synchronous generation and renewable generation. System measures such as regional load and interface flows are also monitored. The regional synchronous generation provides information about the short circuit strength of the region while the regional load and generator reactive power provides the understanding about regional voltage recovery following a disturbance. The percentage non-synchronous generation is also calculated from these measurements. These metrics are monitored dynamically and used to compare the high renewable system performance under various load conditions.

The geographical sub-regions and corresponding boundaries are defined based on the group of geographically coherent machines regardless of ownership and state boundaries. Altogether ten geographical subregions are defined for the study wherein six subregions constitute Minnesota Centric Region. Figure 5-3 shows the geographical subregion mapping with the regions shaded green being the Minnesota-Centric region. The assignment was confirmed after discussion with Technical Team members. The subregion assignment is used to evaluate the production simulation (Plexos) output for challenging periods as well as for obtaining the regional metrics for dynamic simulation. The geographical subregion is assigned to every generator in the entire Eastern Interconnect. Furthermore, all equipment including buses, generators, loads, lines, transformers are assigned subregion based on where they fit in the map shown in Figure 5-3. Table 5-4 lists the subregions and the names used to identify them.

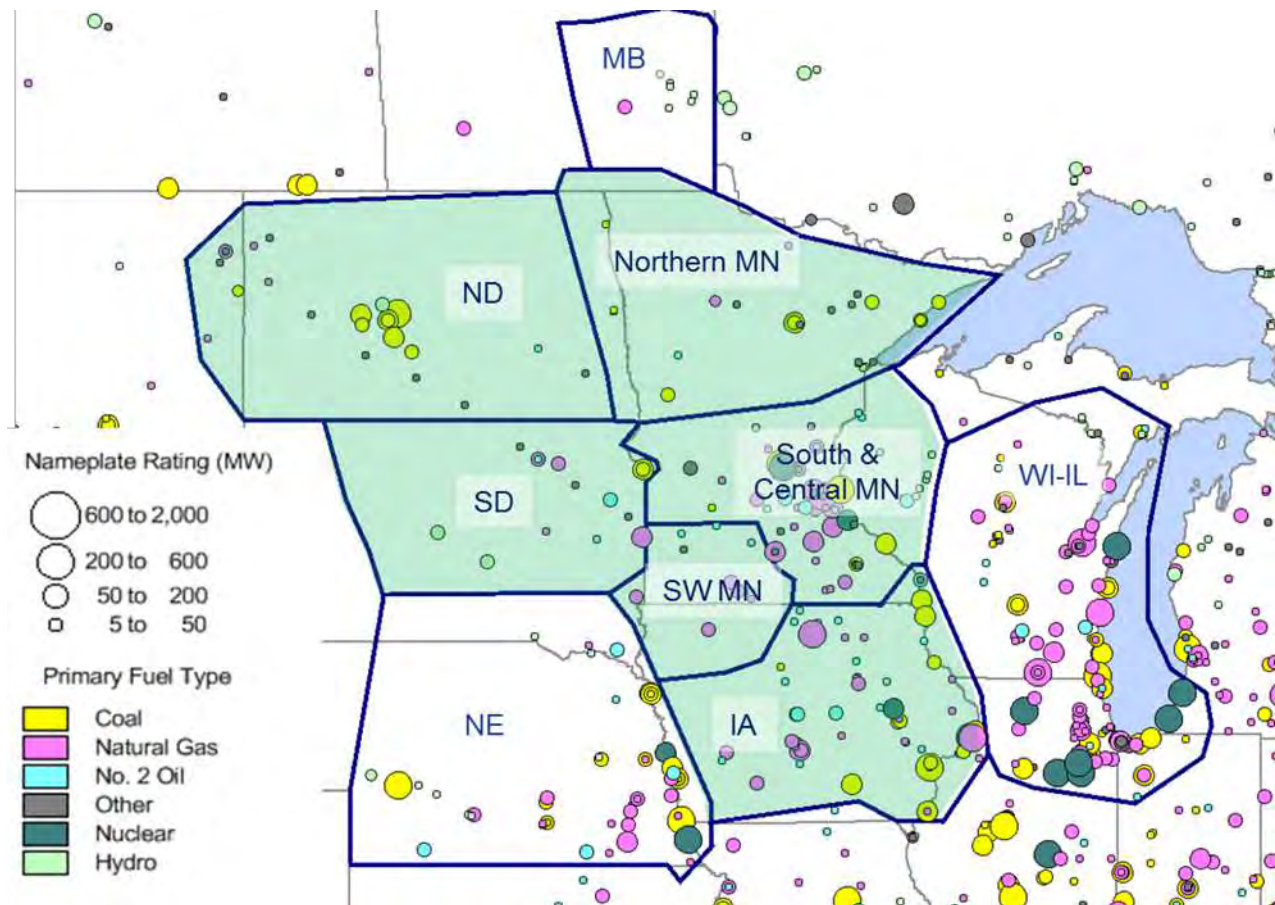


Figure 5-3 Geographical subregions

Table 5-4 Sub region assignment

Sub-Region No.	Name
1	Iowa
2	North Dakota
3	Northern Minnesota
4	South Dakota
5	South & Central Minnesota
6	SW Minnesota
7	Nebraska
8	Wisconsin & Illinois
9	Manitoba
10	Outside

A generic impedance relay model is used on all 220 kV and above the transmission lines throughout Eastern Interconnect. This model is used only for monitoring purpose and will not trip the lines in response to post fault voltage and current.

The instantaneous primary protection zone (Zone 1) is set to cover 85% of the primary line length. Zone 2 protection is delayed by 0.5 seconds and set for 125% of the primary line length. This model was used to identify possible system separation and voltage collapse issues in regions that were not explicitly monitored.

Figure 5-4 shows voltage performance criteria used by WECC. Worst conditions analysis is carried out to identify critical buses with respect to voltage dip and fault induced delayed voltage recovery. All 220 kV and above buses throughout MISO are monitored. With the idea of capturing large post fault transient voltage dip, buses with voltage dip below 20% of initial value for more than 20 cycles are identified. Another criterion is used to screen buses with voltage below 0.7 p.u. after fault clearing. In order not to capture low voltage during stuck breaker faults, where the fault clearing times are longer, the latter criterion is applied 0.15 sec after fault application.

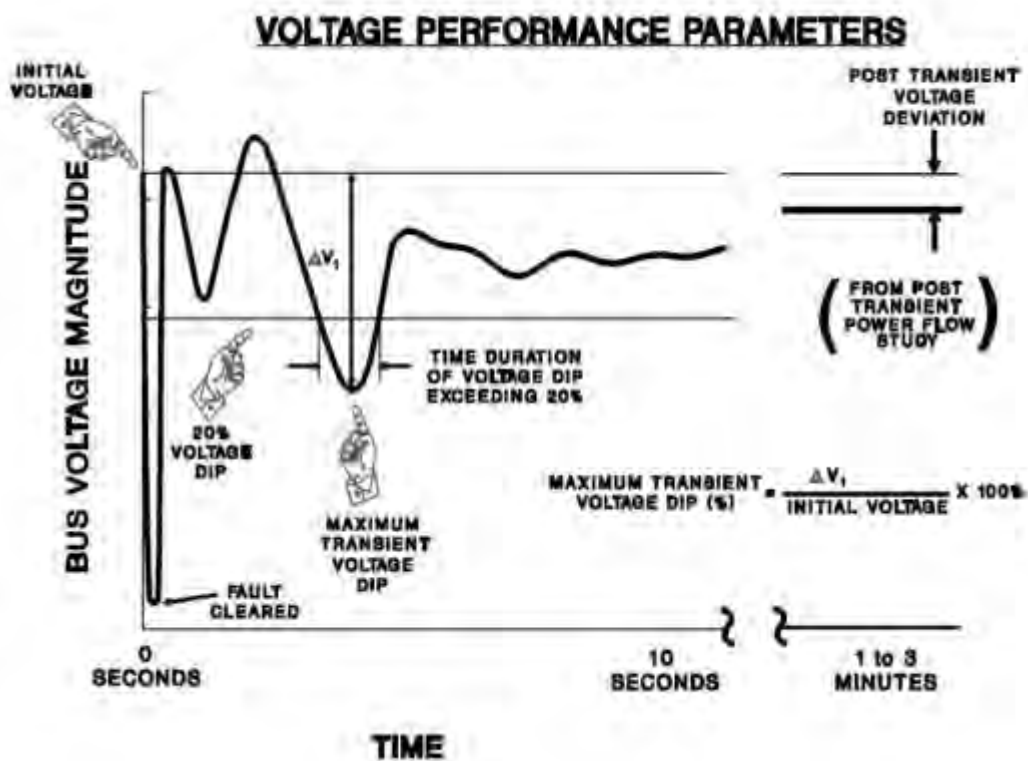


Figure 5-4 Voltage performance metrics

6 PRODUCTION SIMULATION MODEL

6.1 Overview of Production Simulations

The Minnesota Renewable Energy Integration and Transmission Study (MRITS) analyzed three scenarios (Baseline, S1, and S2). The baseline scenario represents the generation, transmission and market system in 2028 if current industry and economic trends continue. S1 represents a future where baseline trends continue, along with Minnesota increasing its renewable penetration to 40% along with small Non-MN distributed solar in MISO. S2 represents a future where baseline trends continue, along with Minnesota increasing its renewable penetration to 50%, and MISO North/Central increases its renewable penetration to 25%.

PLEXOS™, an integrated energy model, was used to do the production simulations. The PLEXOS model was constructed from the existing 2013 MTEP Business As Usual (BAU) dataset for the study year 2028. Then S1 was built from the Baseline by adding new wind and solar generation and transmission upgrades, and S2 was built from S1 by adding yet more wind and solar generation, removing some expansion gas generation and adding additional transmission.

6.2 PLEXOS Overview

PLEXOS was chosen because it can utilize a Day-Ahead Security Constrained Unit Commitment (SCUC) and Real-Time Security Constrained Economic Dispatch (SCED) interleaved market dispatch solution. This type of interleaved modeling, with one simulation feeding into the other, more accurately captures the forecast uncertainties realized between a Day-Ahead and Real-Time markets. Modeling the forecast uncertainty becomes increasingly important when dealing with significant levels of wind resource output which tends to be more stochastic in nature.

Performing an economic production simulation was a principal aspect of the MRITS study to correctly model how the MISO system operates. The vast amount of hourly output such an analysis generates can be crucial in understanding which time periods are the most significant to analyze further. It also provides valuable insight into transmission system utilization, power system flows, and renewable unit curtailment.

6.3 MRITS Production Simulation Model – Source Dataset

MISO used the 2013 MTEP Business as Usual (BAU) future as the source dataset (starting point) for the MRITS analysis. The BAU future is considered the status quo future and continues current economic trends. This future models the power system as it exists today with reference values and trends. Renewable portfolio standards vary by state and 12.6 GW of coal unit retirements are modeled. The MTEP futures are created by MISO and vetted by the MISO Planning Advisory Committee (PAC) stakeholder committee. Information for the dataset is sourced from Ventyx and updated through an extensive internal MISO process to bring it into line with the most current data.

The PLEXOS model footprint includes all areas in the Eastern Interconnect, with the exception of Florida, ISO New England and Eastern Canada as shown in Figure 6-1. Figure 6-2 shows the MISO market footprint. MISO is modeled using membership information dated as of January 2014.

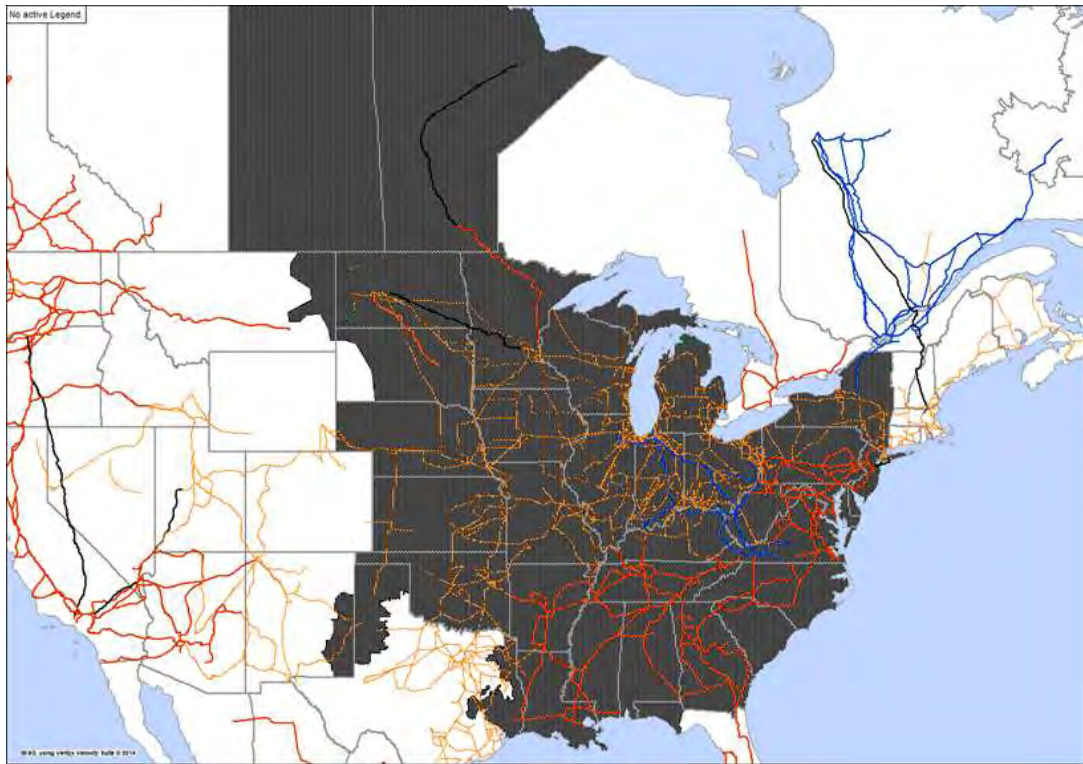


Figure 6-1 Study Footprint

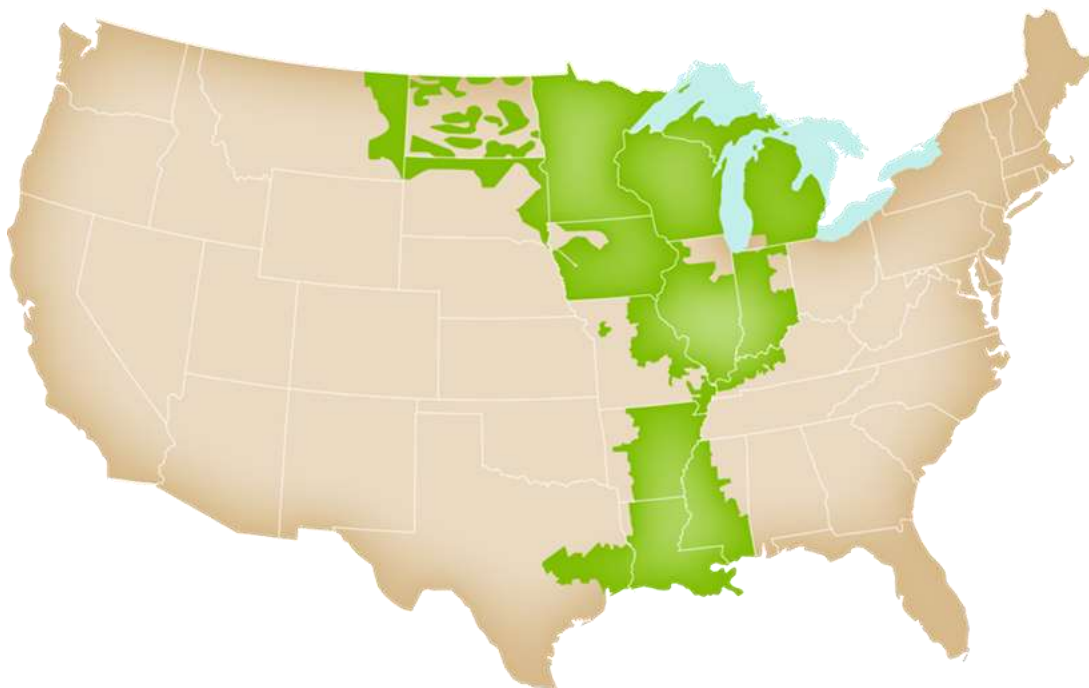


Figure 6-2 MISO's Market Footprint

As part of the MTEP BAU future development process, capacity was added to meet the various planning reserve margin requirements. Renewable resources were added to meet the various state renewable portfolio standards, shown in Figure 6-3, throughout the Eastern Interconnect.

Also between 2013 and 2028, 24,900 MW of capacity was added to MISO to meet the planning reserve margin (14.2%), and 12,200 MW of coal was retired in MISO due to the forecasted effects of prior EPA regulations as shown in Figure 6-4. This does not include coal plant retirements that may result from the EPA's proposed Clean Power Plan (111d).

Capacity additions include wind and demand side resources to meet state mandates along with gas units because of the low natural gas price. Demand and Energy Growth Rate was 1.06%, and all prices escalate at an inflation rate of 2.5%.

Wind and solar plant output was modeled at specific locations with each site having a unique historically based output as demonstrated in Figure 6-5.¹

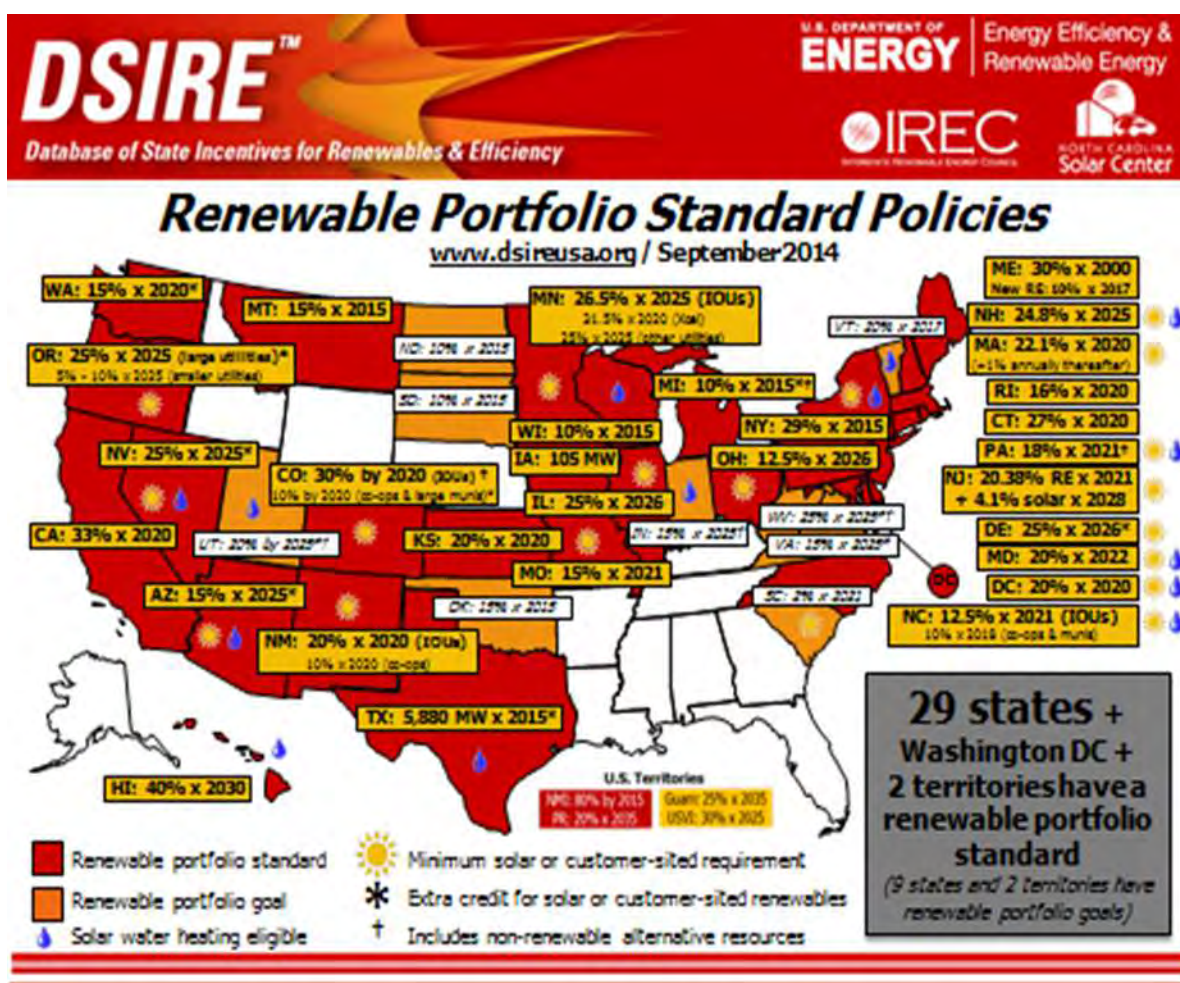


Figure 6-3 State Renewable Portfolio Standard Policies used in the MTEP13 Model

¹ <http://www.dsireusa.org/summarymaps/index.cfm?ee=0&RE=0>

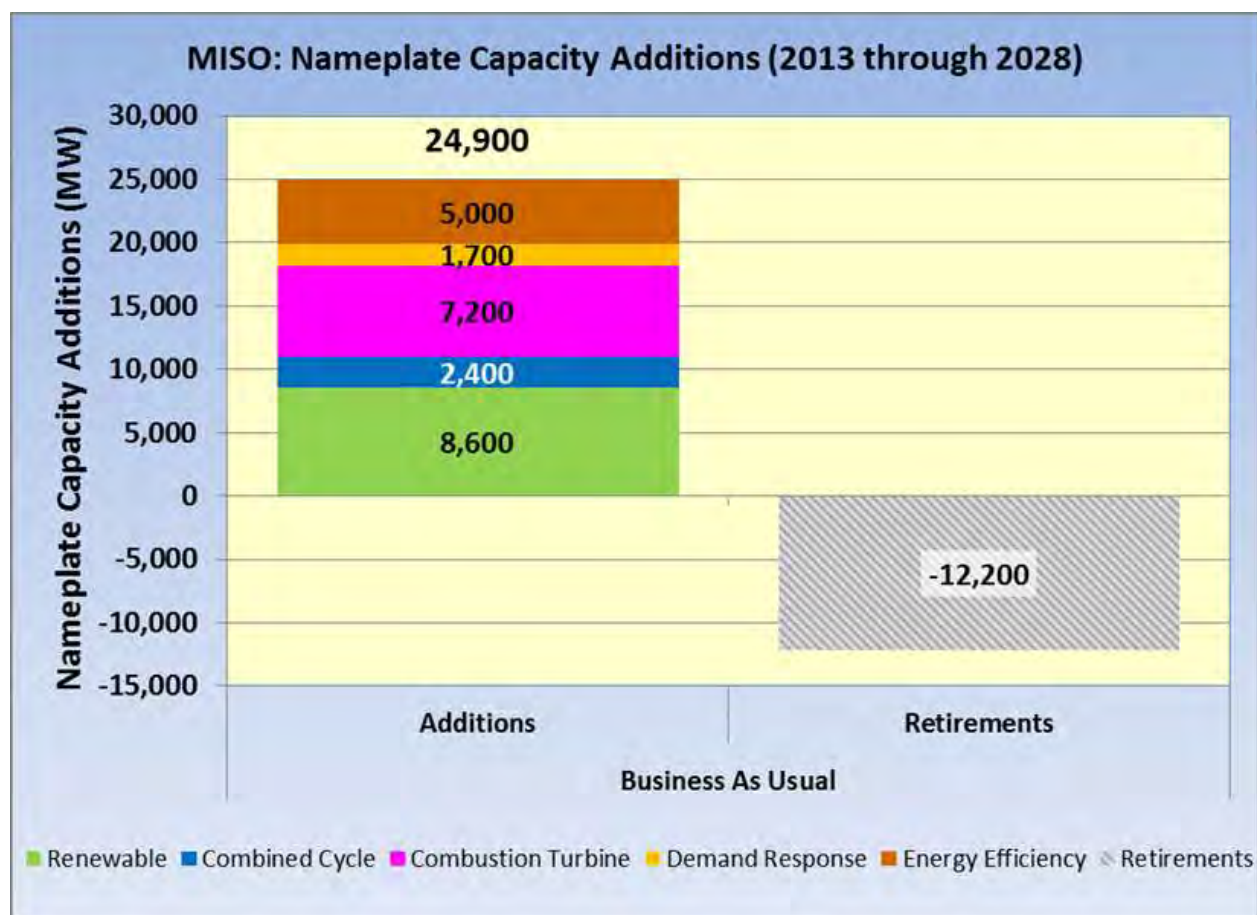


Figure 6-4 MISO's MTEP13 BAU capacity additions and coal Retirements
before changes were made as shown in Figure 6-6 (2013-2028)

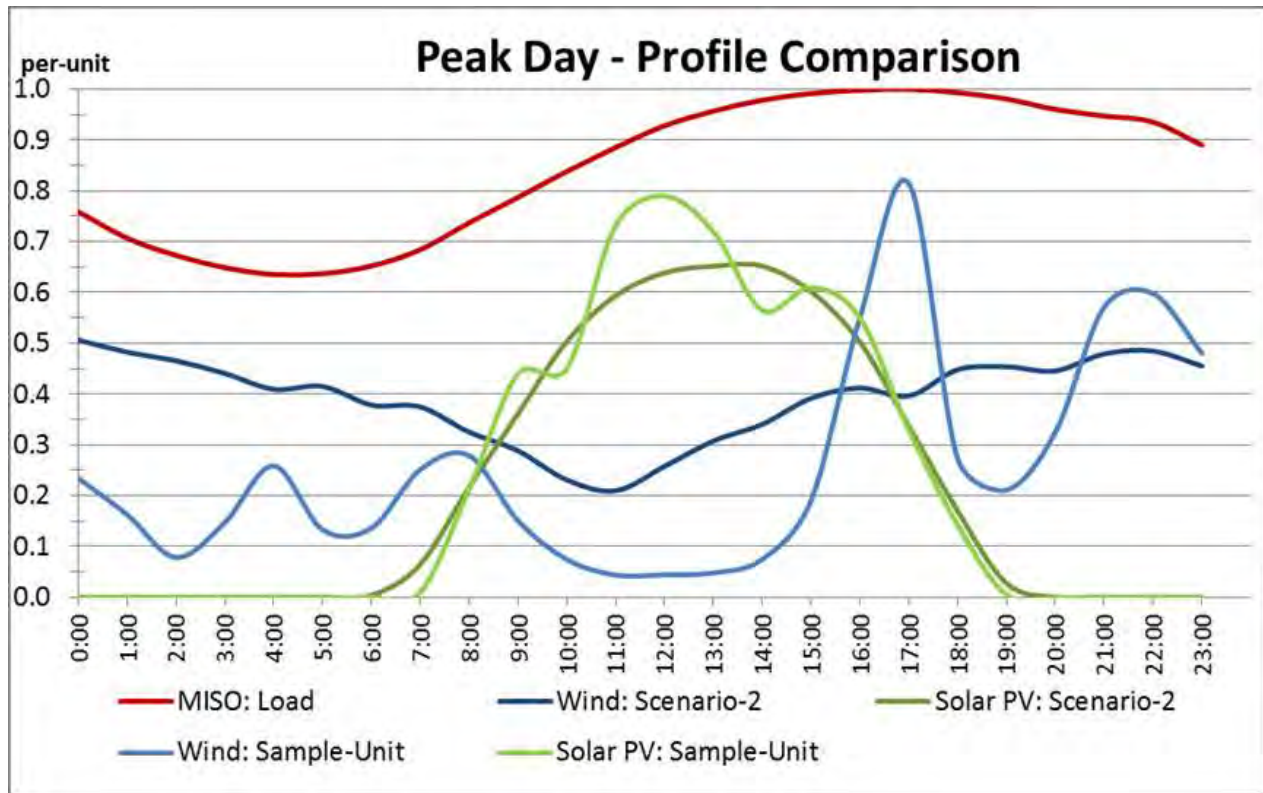


Figure 6-5 Illustration of site specific renewable output

6.3.1 Baseline Scenario

MRITS held slightly different assumptions than the 2013 MTEP BAU future, thus the baseline database needed to be modified to reflect these new assumptions. Wind resources used the same assumptions that the MTEP BAU future did, but solar units were adjusted. The forecasted solar units, totaling 1725 MW, in MISO were removed and 1509 MW of new solar generation was added to the Baseline model per MRITS assumptions.

The siting locations of these units were also changed to reflect a more realistic distribution of solar resources which is explained in the Siting Section. A proxy expansion hydro unit in Manitoba Hydro was removed and replaced with Keeyask, a 695MW unit that has become certain (approved and under construction) since the 2013 MTEP models were built. The 500kV Great Northern transmission line was also added to deliver this hydro power.

6.3.2 Scenarios 1 and 2

Scenario 1 and 2 had different capacity assumptions than the baseline case did so a new capacity expansion was done to reflect these different assumptions. Renewable capacity was increased and thermal capacity was decreased to maintain the same capacity reserve margins as shown in Figure 6-6. The treatment of capacity credit for wind and solar resources is discussed in the following subsection.

Thermal capacity was not reduced for Scenario 1 because capacity reserves were slightly over the requirement in 2028 given the lumpiness of capacity additions, in other words, the generation is not

added in smooth incremental amounts but rather the generation is added in larger blocks. In scenario 2, enough renewables were added to warrant the reduction in thermal capacity.

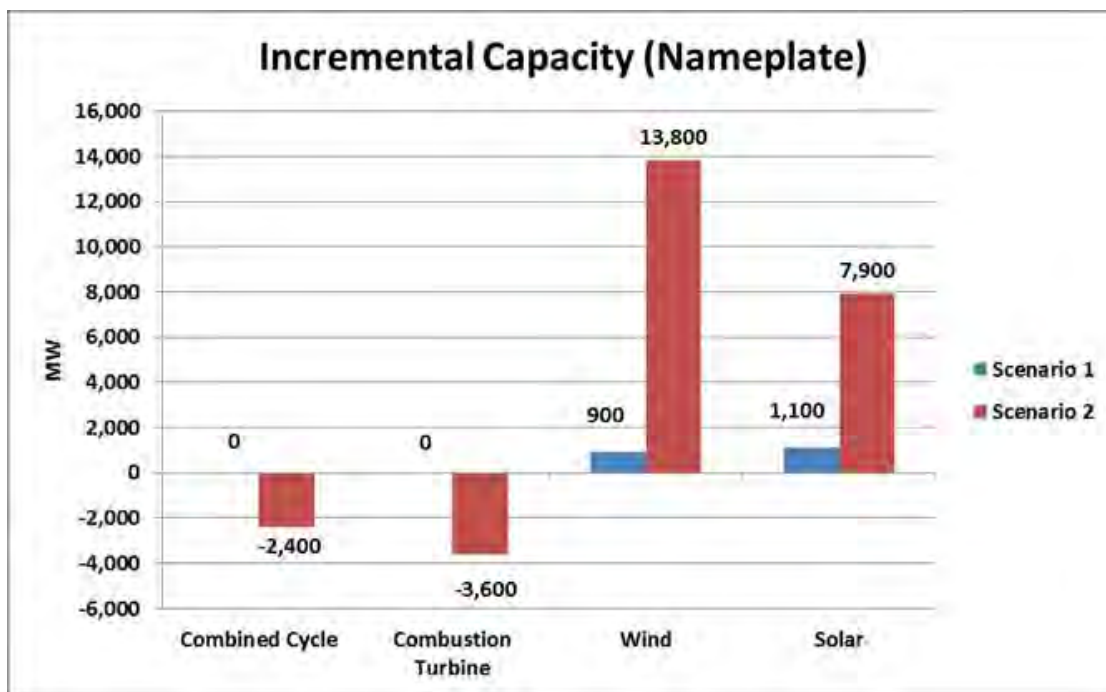


Figure 6-6 Resource Capacity Changes for Scenarios 1 and 2

6.3.3 Capacity Credit for Wind and Solar Resources

A capacity credit value was needed for the wind and solar renewables in order to perform the resource forecasting capacity expansion. For each of those resource types a currently developed MISO process was utilized to determine what capacity value to use for the MRITS study.

The resulting capacity credit values were:

Baseline and S1 Wind:	14.1%
S2 Wind:	11.8%
Solar:	40 %

6.3.3.1 Wind Capacity Value

For the wind capacity credit, this study referred to the MISO report² findings.

Both the Baseline and Scenario1 models used the value of 14.1% of nameplate. Those cases both have levels of wind energy penetration, 14% and 15.2% respectively, which are close to the current MISO system amount of 13%, installed.

²Planning Year 2014-2015, Wind Capacity Credit,
<https://www.misoenergy.org/Library/Repository/Study/LOLE/2014%20Wind%20Capacity%20Report.pdf>

But for Scenario 2 which had a significant increase in the MISO penetration of wind to 23.8%, the Figure 6-7 from the report³ was used to interpolate a capacity value of 11.8% for wind. In the higher wind penetration regions, 15%+, as the figure shows, the wind capacity credit decreases due to a saturation of wind energy during peak times. Note that the figure shows only the 20 GW and 30 GW penetration data points and these were converted to 21.2% and 31.8% penetration, respectively, based on the 94,298 MW 2013 MISO Peak Load used for that figure.

6.3.3.2 Solar Capacity Value

For the solar capacity value, this study referred to the MISO Resource Adequacy Business Practice Manual⁴ rules for non-wind, intermittent resources. The manual⁵ indicates that the following be used:

“Intermittent Generation and Dispatchable Intermittent Resources that are not powered by wind must supply MISO with the most recent consecutive three years of hourly net output (in MW) for hours 1500 – 1700 EST from June, July and August. For new resources, or resources on qualified extended outage where data does not exist for some or all of the previous 36 historical months, a minimum of 30 consecutive days’ worth of historical data during June, July or August for the hours of 1500 - 1700 EST must be provided.”

So using only data during that prescribed time period and the 2006 NREL solar set of information provided for the sites used in the MRITS study, a capacity value of 40% of solar nameplate was calculated based on the capacity factor deterministic approach.

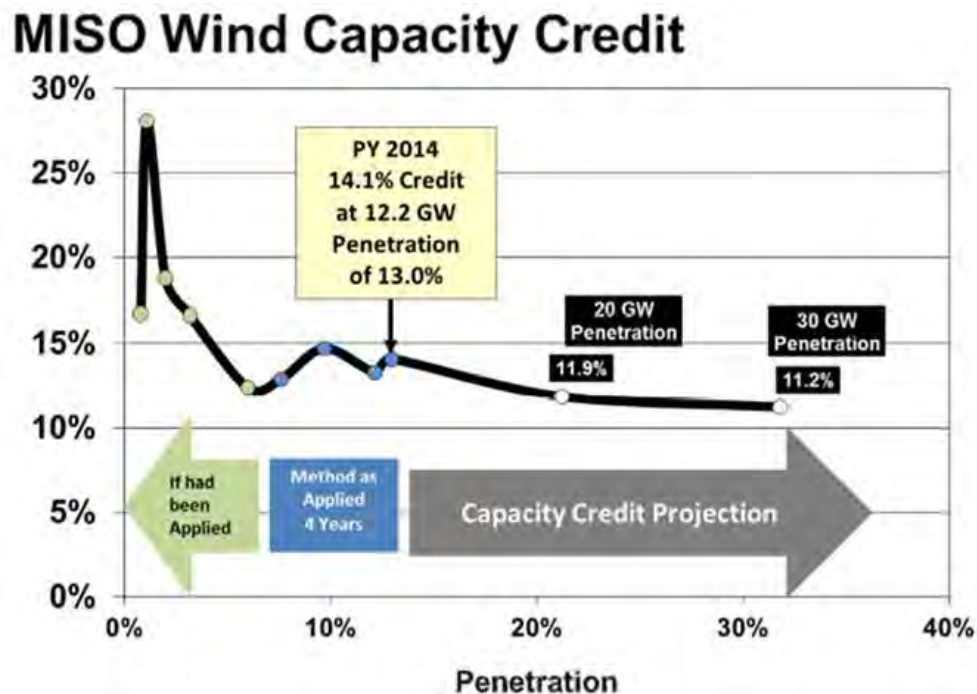


Figure 6-7 Plot of Wind Capacity Credit versus Penetration Level, from MISO Report

³ <https://www.misoenergy.org/Library/Repository/Study/LOLE/2014%20Wind%20Capacity%20Report.pdf>

⁴ <https://www.misoenergy.org/layouts/MISO/ECM/Redirect.aspx?ID=19206>

⁵ Ibid. Section 4.2.2.1 (page-34)

The 40% capacity factor for solar was used in the resource forecasting step when determining which and how many other non-renewable resources to add to maintain the planning reserve margin in the future year.

For the load-flow analysis, it was decided to further stress the transmission system with a higher value of solar output beyond its capacity factor rating. A scatter plot of wind vs. solar output was compiled which can be seen in Figure 6-8. This figure shows that when the wind output is in the range of 20% as during peak load-flow type conditions or when it's at a 90% range during off-peak load-flow type conditions, solar output could be in the high range of 60%. Based on that high range level value, 60% was chosen as the load-flow assumption level for solar.

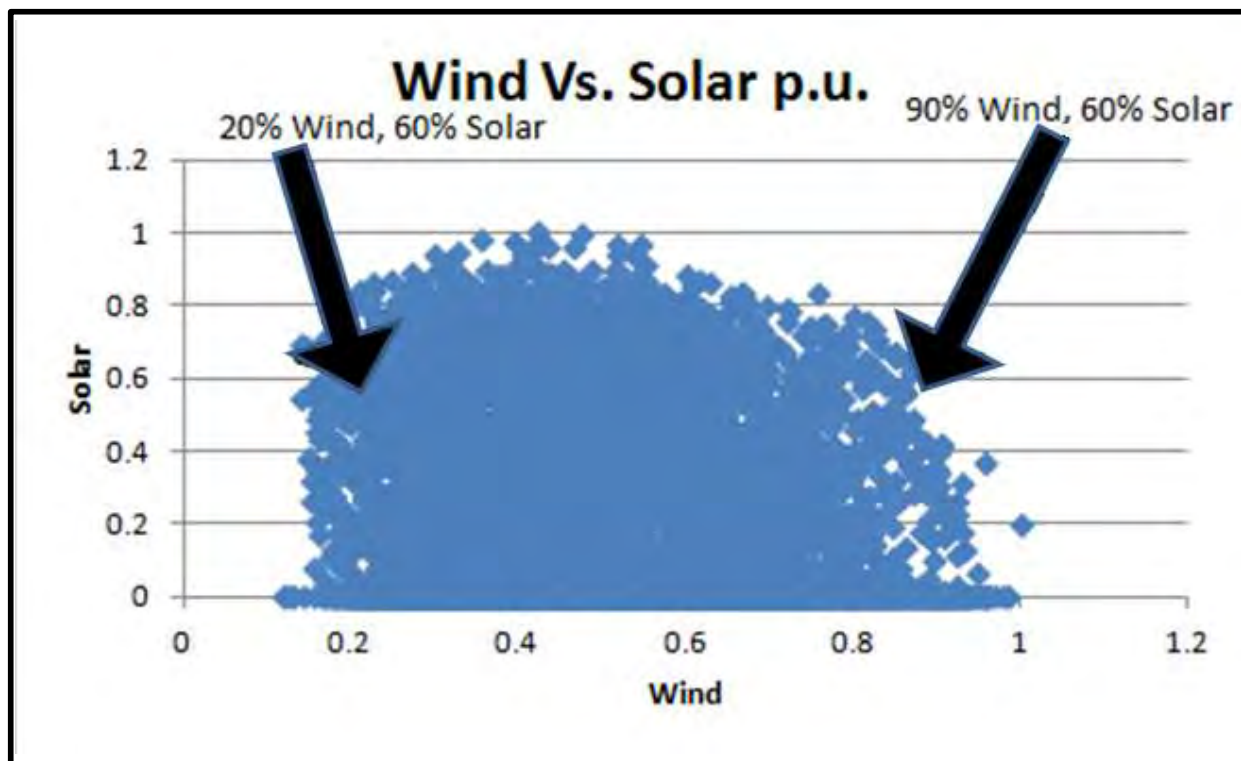


Figure 6-8 Scatter Plot of Wind versus Solar Output

6.3.4 Forecast Uncertainty

The MRITS study incorporates wind, solar and load uncertainty to more accurately reflect the challenges associated with large scale renewable integration. Renewable profiles were provided by the National Renewable Energy Lab (NREL).

<u>Wind uses the NREL EWITS wind dataset:</u>	Unit commitment uses the 4-hour ahead wind profile Dispatch uses the actual wind site output
<u>Solar uses the NREL ERGIS solar dataset:</u>	Unit commitment uses a MISO aggregate solar profile. Dispatch uses the actual solar site output
<u>Load uses historic load data:</u>	Unit commitment uses a stochastic load profile. Dispatch uses the historic actual profiles

6.3.4.1 Wind

All 2006 wind data comes from the NREL EWITS wind data set. Two separate wind forecasts were considered, the Next Day (ND) and the 4-hour ahead (4HR) as shown in Figure 6-9. The plot shows normalized traces of hourly wind power for one week. The 4 hour wind forecast provided by NREL was used as this more accurately approximates the final generation commitment MISO would have going into the Real Time market. The Actual output is the estimated wind that was actually produced for the given hour as provided by NREL⁶.

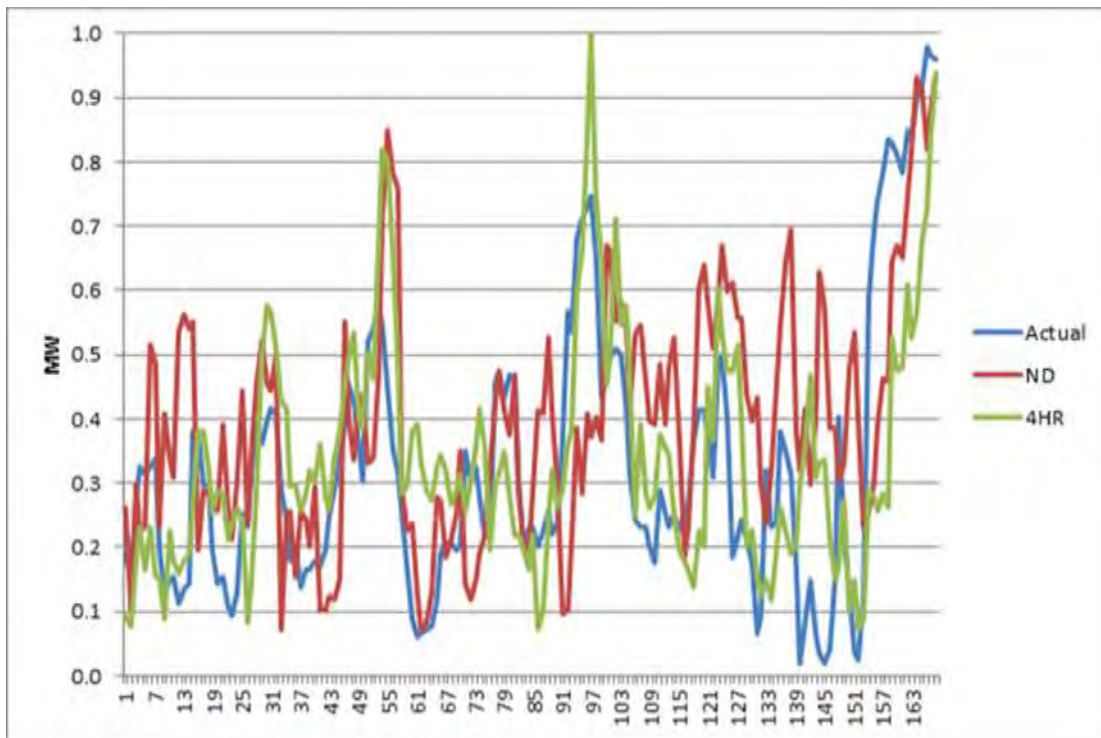


Figure 6-9 Sample of Hourly Forecast and Actual Wind Site Output (1st week of July)

⁶ http://www.nrel.gov/electricity/transmission/wind_integration_dataset.html

6.3.4.2 Solar

Actual real time solar data comes from NREL. It is a combination of Eastern Renewable Generation Integration Study (ERGIS) data for non-Minnesota sites and newly created data for Minnesota sites. The forecast is created by summing all profiles together and creating a single shape for the entire region. This shape is scaled back down to the size of each individual solar site.

The forecast will take into account wide spread cloudiness since it is the aggregate of the actual profiles, but spotty clouding will be washed out because of the aggregation. The solar arc can be perfectly forecasted but cloud cover creates the uncertainty in the forecast.

Figure 6-10 shows the output of 2 Solar Sites, and demonstrates the differences between individual locations, and how they each compare to the forecast. Solar output is shown as a percentage of its Direct Current rating.

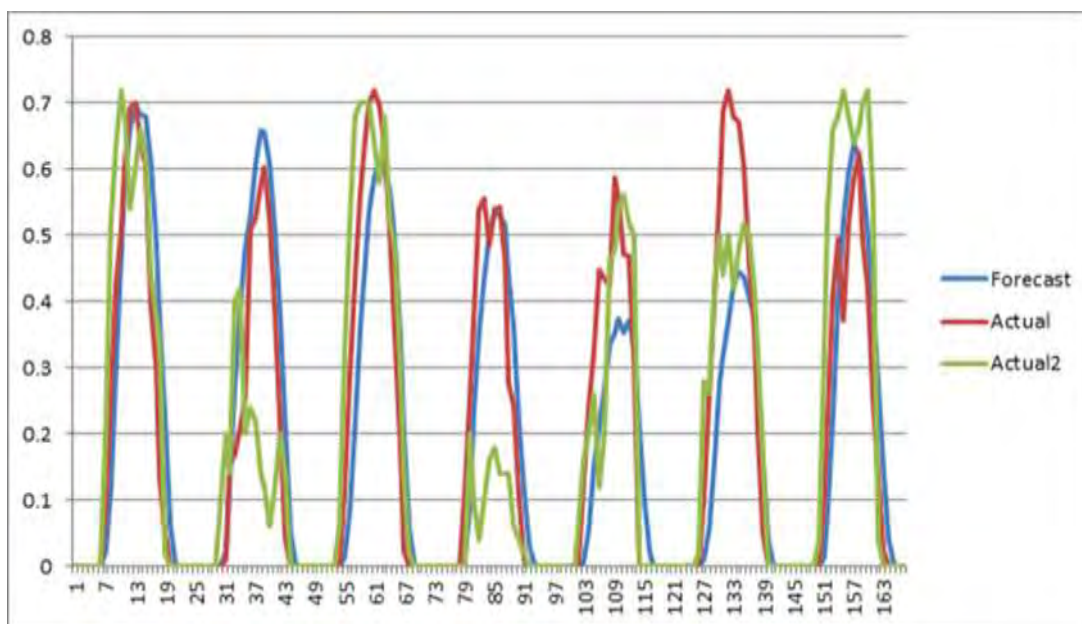


Figure 6-10 Sample of Hourly Forecast and Actual Solar Site Output (1st week of July)

6.3.4.3 Load

Actual load profiles are historic 2006 shapes. Forecasts are created by compiling statistics from the MISO market between 2008 and 2011 and applying those to the actual shapes. A random draw was done using these statistics to simulate the historic differences between the forecast and the actual load. The day-ahead load forecast was used and not a 4-hour forecast because the day-ahead is a discrete and separate forecast while the 4 hour is simply a snapshot of the rolling forecast.

Figure 6-11 shows a sample of load for a week, along with the random draw forecast which was used for this study.

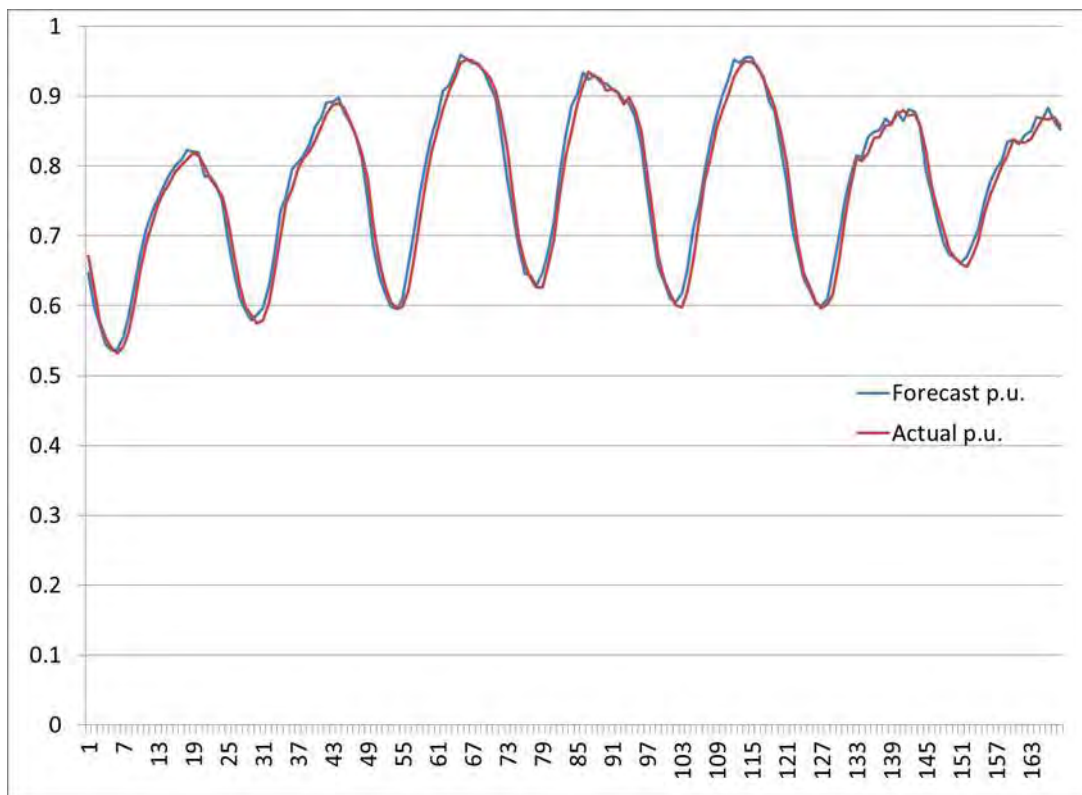


Figure 6-11 Sample Minnesota Load Output (1st week of July)

7 OPERATIONAL PERFORMANCE RESULTS

7.1 Scenarios for Production Simulation Analysis

As described in Chapter 2, the study was designed to evaluate scenarios with three levels of renewable energy (RE) penetration in Minnesota (see Table 7-1). These 3 levels of RE penetration were analyzed with five production simulation cases. Two of the five cases had different assumptions for coal plant commitment, forced outage modeling, coal unit retirements, and modeling of the Missouri River hydro plants. The modeling assumptions for each case are summarized in Table 7-2. Scenario 1a is a sensitivity case with respect to Scenario 1. That is, Scenarios 1 and 1a have the same renewable energy penetration, but with different system operating assumptions. Similarly, Scenario 2a is a sensitivity case with respect to Scenario 2. Thus, the original three scenarios expanded to five scenarios for this aspect of the technical analysis.

Table 7-1 Study Scenarios

Scenario	Minnesota RE Penetration	MISO Wind & Solar Penetration (including MN)
Baseline	28.5%	14.0%
Scenario 1	40.0%	15.0%
Scenario 2	50.0%	25.0%
Note: MISO has an additional 3% renewable energy penetration in all scenarios from existing small biomass and small hydro.		

Table 7-2 Major Assumptions for Production Simulation Analysis of Study Scenarios

	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Coal plants modeling: Must-run (MR) or Security-Constrained Economic Commitment (SCEC)	MR	MR	SCEC	MR	SCEC
Forced outages included in generation modeling	No	No	Yes	No	Yes
Nine Minnesota-Centric coal units retired	Yes	Yes	No	Yes	No
Improved modeling of Missouri River hydro generation	No	No	Yes	Yes	Yes

Minnesota load is served by a group of utilities and cooperatives with service territories that extend beyond the boundaries of the State of Minnesota. Therefore, the results of the production simulation analysis are summarized for the “Minnesota-Centric Region”, which consists of all generating resources operated by and system loads served by the Minnesota utilities.

Figure 7-1 shows a map of the Minnesota-Centric Region. The dots represent generating stations owned and operated by the Minnesota Utilities. The individual utilities are listed in the figure.

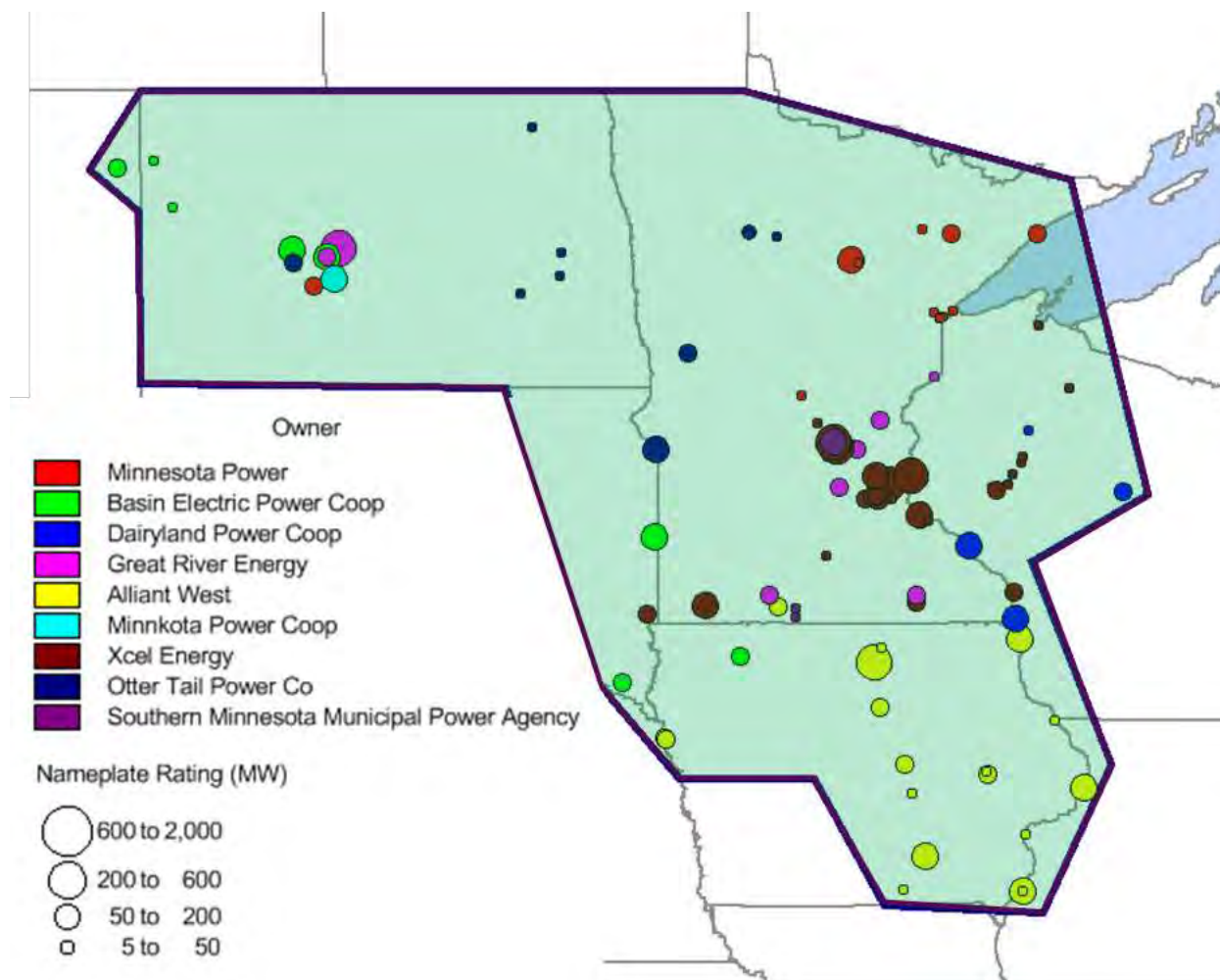


Figure 7-1 Minnesota-Centric footprint for production simulation (Plexos) Analysis
Dots indicate generating plants owned by Minnesota Utilities.

7.2 Annual Energy

Table 7-3 shows annual load, wind and solar energy for the Minnesota-Centric region for the study scenarios. The system load energy is, of course, the same for all scenarios. The bottom two rows show the MW rating of assumed wind and solar generation resources in the Minnesota-Centric region, which increase from the Baseline, to Scenarios 1/1a, and then further increase to the values in Scenarios 2/2a.

Note that the wind and solar energy penetration levels shown in this table are for the Minnesota-Centric Region and not specifically for the State of Minnesota. The amount of wind and solar generation resources included in the system models was calculated to meet the Minnesota RE penetrations specified in the study objectives (see Chapter 3).

In the production simulation analysis, the energy is summarized by “owner” (i.e., the utility which owns the bus where the generation is connected) consistent with the operation of the system. Therefore, the wind and solar energy penetration levels shown in the table are calculated for the entire Minnesota-Centric region, which includes all generating resources operated by and system loads served by the Minnesota utilities.

The results show that wind and solar curtailment is relatively small in all the scenarios. The levels of curtailment are considered to be within reason and not sufficient to be of concern. Experience from grid operations and from other renewable integration studies has shown that it is not economically justifiable to eliminate all causes of curtailment for all hours of the year. A small amount of curtailment is to be expected for any system.

Further analysis of wind and solar curtailment is presented in a subsequent section of this report.

Table 7-3 Annual Load, Wind and Solar Energy for Minnesota-Centric Region

	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Load Energy (MWh)	147,807,020	147,807,020	147,807,020	147,807,020	147,807,020
Available Wind Energy (MWh)	37,286,193	45,753,928	45,753,928	61,789,277	61,789,277
Delivered Wind Energy (MWh)	37,129,632	45,298,460	45,025,066	60,467,557	60,799,826
Curtailed Wind Energy (MWh)	156,561	455,468	728,862	1,321,700	989,451
Curtailed Wind Energy	0.42%	1.00%	1.59%	2.14%	1.60%
Available Solar Energy (MWh)	702,562	2,002,969	2,002,969	6,870,164	6,870,164
Delivered Solar Energy (MWh)	701,936	2,002,869	1,998,268	6,841,300	6,853,503
Curtailed Solar Energy (MWh)	626	100	4701	28,864	16,661
Curtailed Solar Energy	0.09%	0.00%	0.23%	0.42%	0.24%
Wind Penetration	25.12%	30.65%	30.46%	40.91%	41.13%
Solar Penetration	0.48%	1.36%	1.35%	4.63%	4.64%
Wind+Solar Penetration	25.60%	32.00%	31.81%	45.54%	45.77%
MW Rating of Wind Fleet	11,039	12,970	12,970	18,140	18,140
MW Rating of Solar Fleet	470	1367	1367	4588	4588

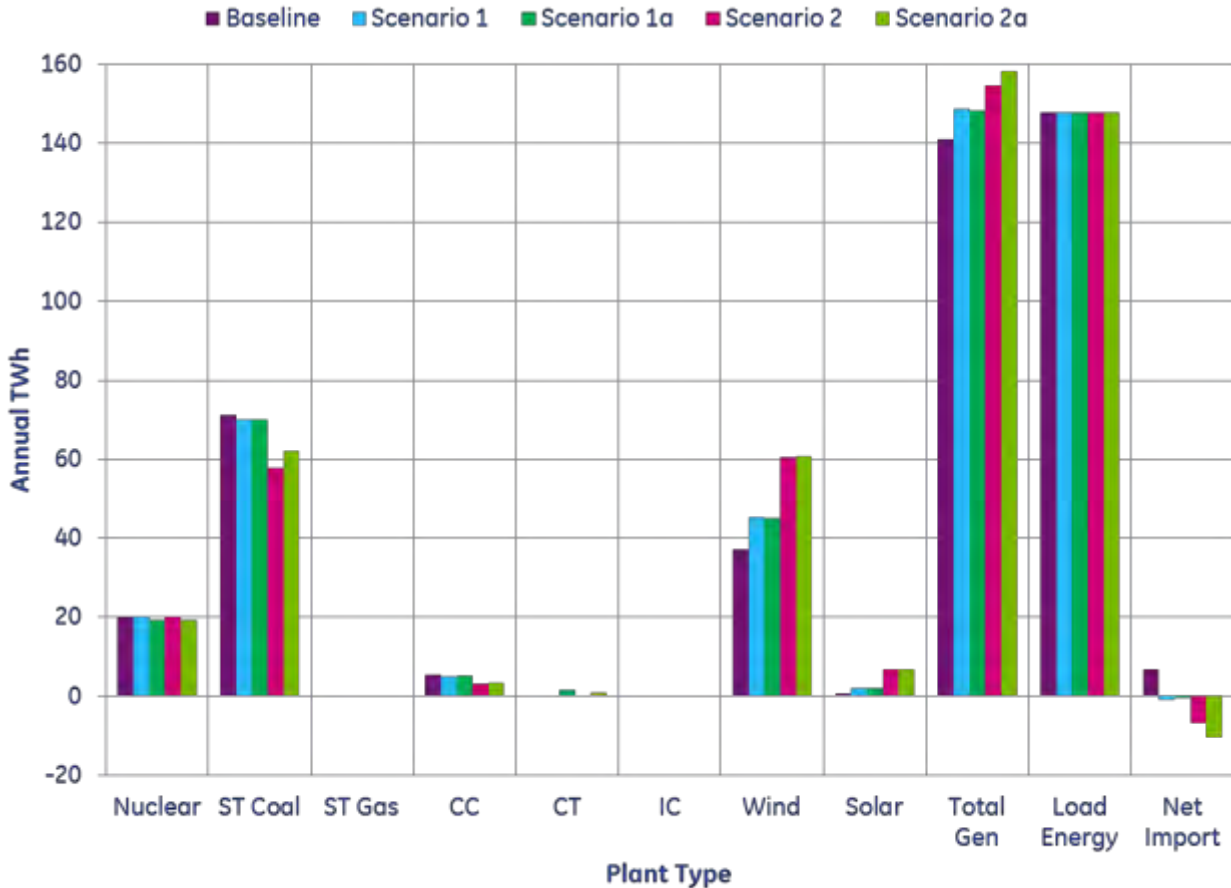


Figure 7-2 Annual generation in TWh by unit type for Minnesota-Centric region

Figure 7-2 shows the annual load and generation energy by type for the Minnesota-Centric region. Comparing Scenarios 1 and 1a (40% MN renewables) with the Baseline,

- Wind and solar energy increases by 8.5 TWh, all of which contributes to bringing Minnesota from 28.5% RE penetration to 40% RE penetration
- There is very little change in energy from conventional generation resources.
- Most of the increase in wind and solar energy is balanced by a decrease in imports
- The slight reduction in nuclear energy in Scenario 1a is due to forced outages.

Comparing Scenarios 2 and 2a (50% MN renewables) with Scenarios 1 and 1a (40% MN renewables),

- Wind and solar energy increases by 20 TWh. Of this total, 4.8 TWh brings Minnesota from 40% to 50% RE penetration and the remainder contributes to bringing MISO from 15% to 25% RE penetration
- Most of the increase in wind and solar energy in the Minnesota-Centric region is balanced by a decrease in coal generation and imports from neighboring regions

- Gas-fired combined-cycle generation declines from 5.0 TWh in Scenario 1 to 3.0 TWh in Scenario 2

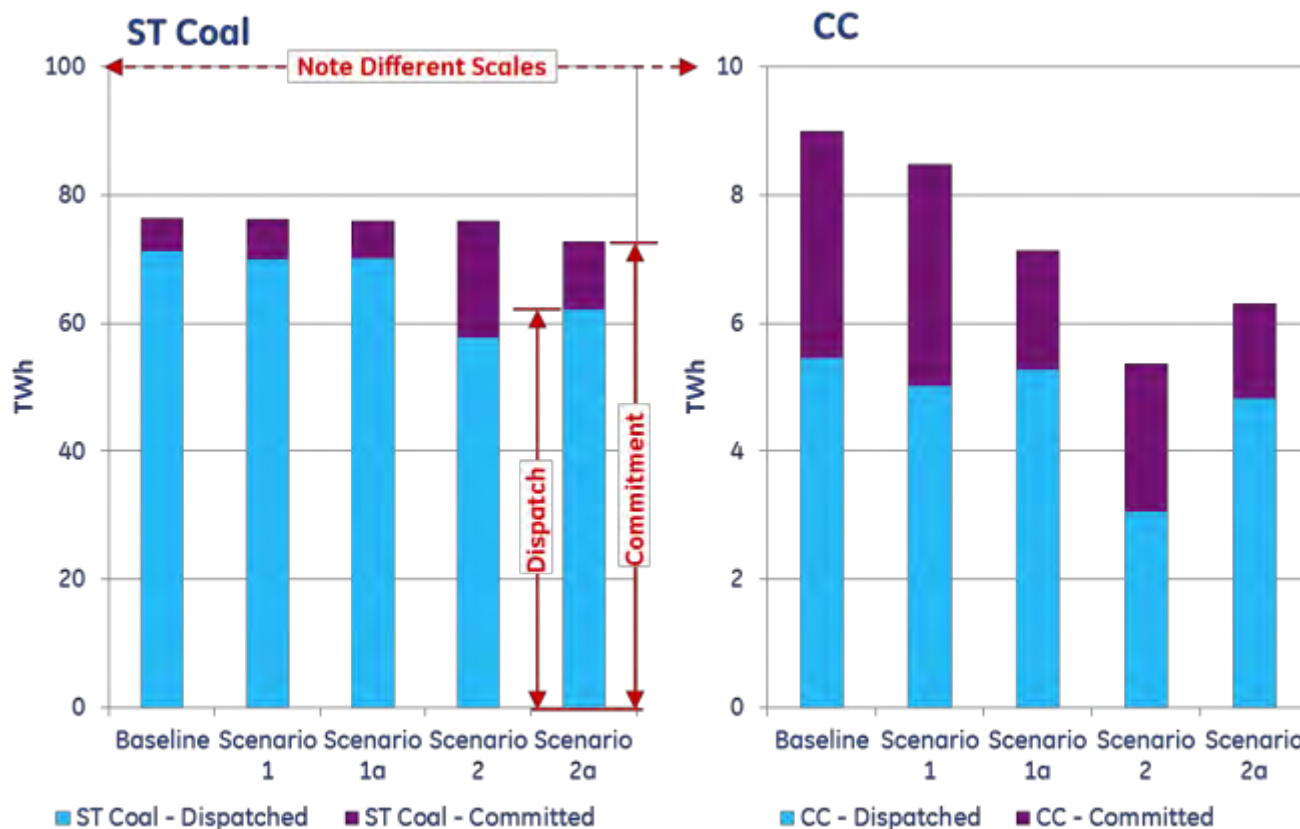


Figure 7-3 Annual Committed Capacity and Dispatch Energy for Coal and Combined-Cycle Units in the Minnesota-Centric Region

The left side of Figure 7-3 shows annual committed capacity and dispatched energy for coal units. In this figure, the total height of each bar indicates total annual coal unit committed capacity for the Minnesota-Centric Region. This is calculated by multiplying the hours online by the unit rating for each coal unit, and then totaling the values for all coal units. The light-blue segment of each bar is the energy dispatched (generated) from the coal units (i.e., the sum of energy output for all hours for all coal units). Comparing the Baseline with Scenarios 1 and 1a, there is no significant difference in coal unit commitment or dispatch. In Scenario 2, the dispatched energy from the coal units declines relative to the previous scenarios due to the increase in wind and solar generation. However, the coal fleet commitment remains nearly the same because many coal units in Scenario 2 are assumed to be must-run and are not decommitted during periods of high wind and solar generation. In Scenario 2a, all coal units are economically committed/decommitted per market signals, so the overall commitment of the coal fleet is lower than in Scenario 2. Note that the coal fleet dispatch in Scenario 2a is higher than Scenario 2. This is because Scenario 2 assumes that 9 coal units in the Minnesota-Centric region would be retired and Scenario 2a assumes that those units would be available to operate.

The right side of Figure 7-3 shows similar information for the combined-cycle fleet. Comparing Scenarios 1 and 1a with Scenarios 2 and 2a, it is evident that utilization of the combined cycle fleet declines as wind and solar energy increases.

The figure also indicates that CC fleet operation is more efficient in Scenario 1a (with coal units economically committed) than in Scenario 1 (with coal units assumed to be must-run). That is, the dispatched CC fleet energy output is a higher percentage of the CC fleet commitment. A similar observation can be made by comparing Scenario 2a with Scenario 2.

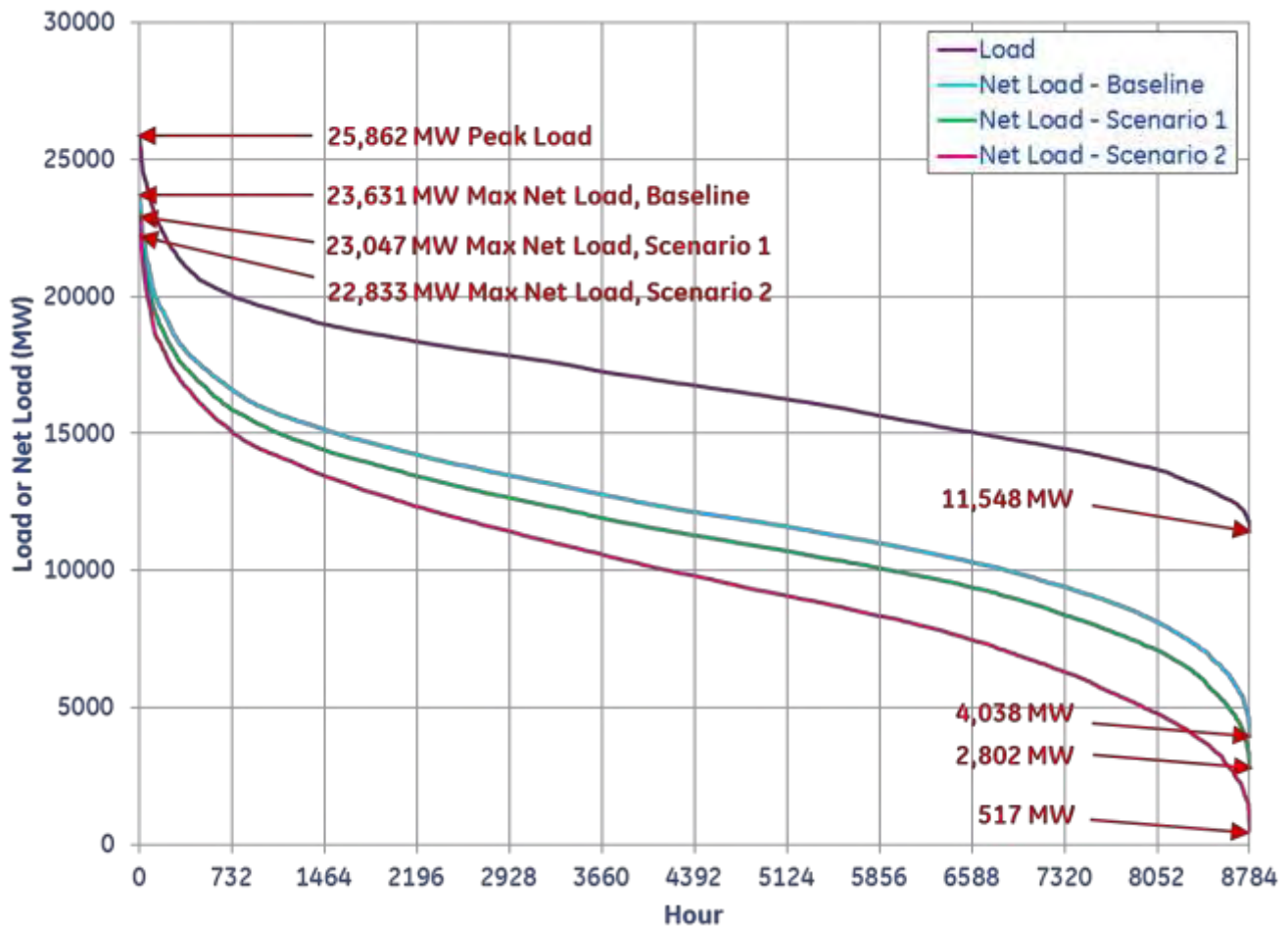


Figure 7-4 Annual Load and Net Load Duration Curves for Minnesota-Centric Region

The annual load and net load¹ duration curves for the Minnesota-Centric region are shown in Figure 7-4 for the different scenarios. (Note, the net loads for scenarios 1a and 2a are essentially unchanged from scenarios 1 and 2 and are not shown here.) The areas between the curves represents the impact of the increasing renewable energy penetrations. The addition of over 11,000 MW of renewable capacity from the Baseline Scenario to Scenario 2 reduced the peak net load by less than 800 MW while the minimum load was reduced by over 3,500 MW. The entire fleet of almost 23,000 MW of renewable capacity reduced the net peak load by about 3,000 MW while the minimum load was reduced by slightly more than 11,000 MW.

¹ Net load is calculated as hourly load energy minus wind and solar generation

It is this fact that makes the cycling capability and minimum stable operating points of the conventional generation critical factors in the analysis.

The timing of the renewable energy is also reflected in Figure 7-5, which shows the annual duration curves of the net energy imports for the Minnesota-Centric region. The overall region is initially a net importer for the year but the increasing amounts of renewable energy shifts it to a net exporter. However, it can be seen that there is little change in the peak imports while the maximum exports increase from a little over 3,500 MW to 6,650 MW.

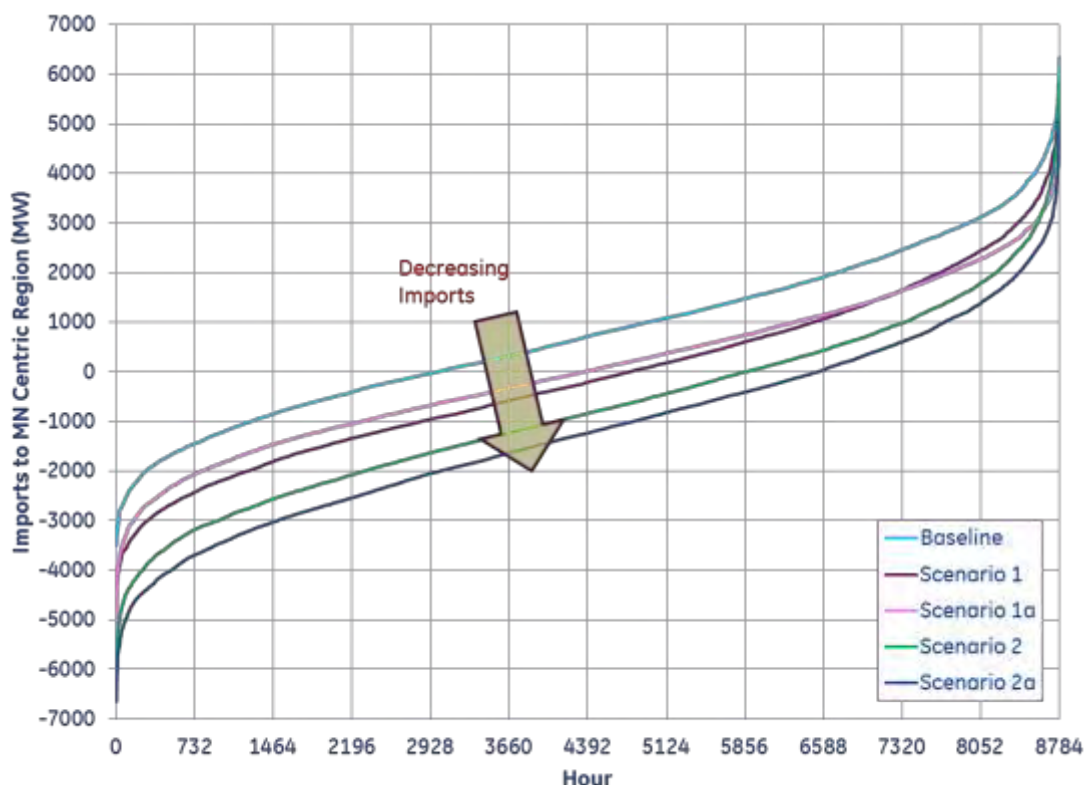


Figure 7-5 Annual Duration Curves of Energy Imports for Minnesota-Centric Region

7.2.1 Aggregate Wind and Solar Plant Capacity and Power Output

The dashed curves in Figure 7-6 show duration curves of the aggregate wind energy from all wind plants in the Minnesota-Centric region. Comparing the curves for the three scenarios shows the increase in wind energy from the Baseline to Scenario 1 to Scenario 2. The solid lines are duration curves of the aggregate ratings of the wind plants on-line. If a wind plant has no power output, then it is considered to be off-line with its power converters idle. If a wind plant is producing power, then it is considered to be on-line and all of its wind turbines and power converters are in-service and connected to the power grid. The flat shapes of these curves indicate that nearly all of the wind plants are on-line for nearly all hours of the year. The importance of this observation is discussed further in Section 7.7.1 (% non-synchronous generation and its impact on relative system strength).

Figure 7-7 is a similar plot for PV solar plants. The solid curves showing aggregate capacity on-line are essentially flat at full fleet rating for the daytime hours and flat at zero for nighttime hours.

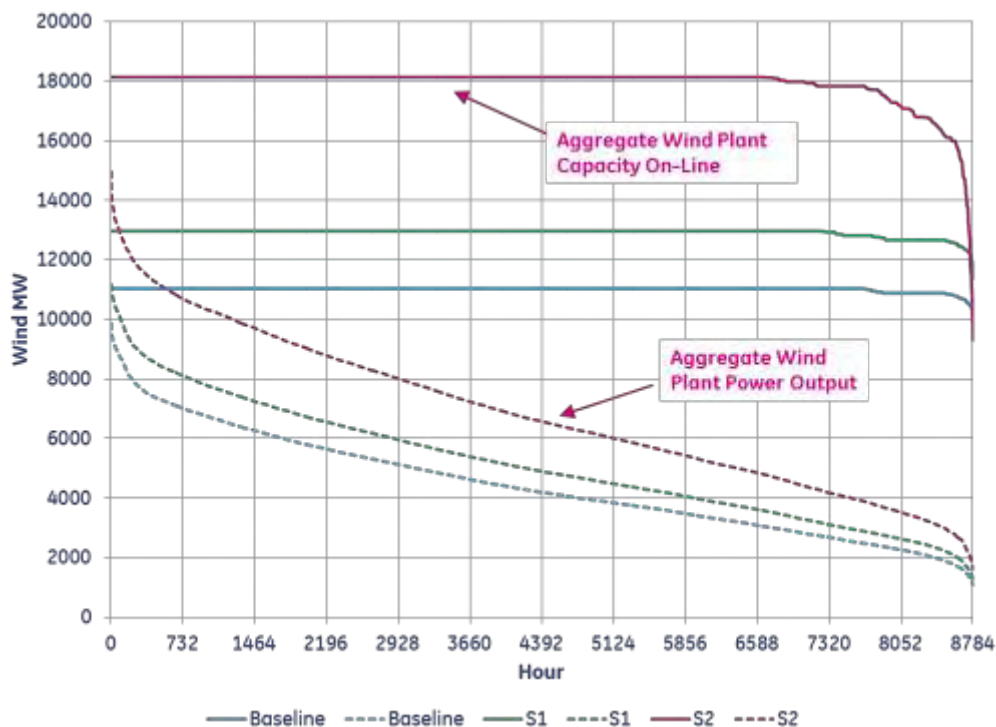


Figure 7-6 Duration Curves of Aggregate Wind Plant Capacity On-Line and Aggregate Wind Plant Power Output for Minnesota-Centric Region

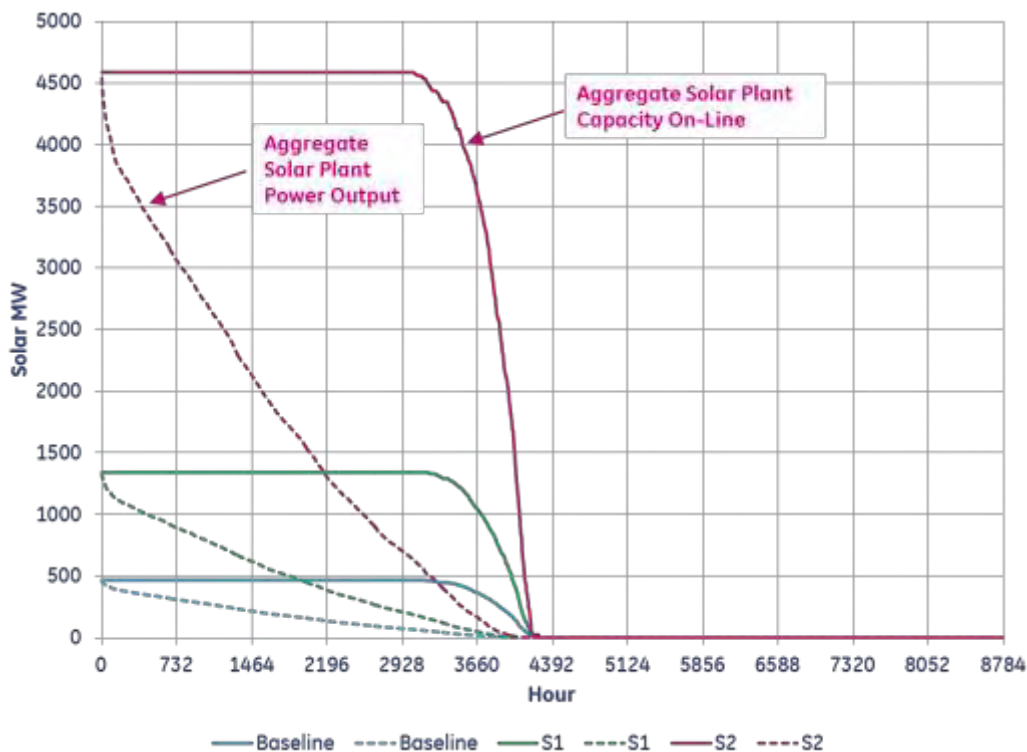


Figure 7-7 Duration Curves of Aggregate Solar Plant Capacity On-Line and Aggregate Solar Plant Power Output for Minnesota-Centric Region

Comparisons of Generation Fleet Utilization for Study Scenarios Table 7-4 gives a more detailed breakdown of the commitment and dispatch by generation type for Scenarios 1 and 1a. As explained earlier, the “MWh Committed” reflects the entire rating of the plants whenever they are on line while the “MWh Dispatched” only reflects the actual energy output. The column “CF” is the capacity factor, which is the energy output divided by the capacity of the fleet times 8784 hours in the year. The next column, “Online CF”, is the average capacity factor over just those hours when the units are on. The clearest example of these terms is with the Combined Cycle units (CC). While the overall capacity factor only change slightly between the two scenarios, from 15% to 16%, the online CF, or average operating level, increased from 59% to 74% reflecting a much more efficient level of operation when the coal plants are permitted to cycle. Note, only units that operated at some time during the year were counted in the fleet, so the capacities could change slightly between scenarios. Table 7-5 shows a similar comparison for Scenarios 2 and 2a. Allowing the coal plants to cycle reduced their average capacity factors from 69% to only 58% but their average level of operation increased from 76% to 85%. The combined cycle units also increased the overall efficiency of their operation.

**Table 7-4 Comparison of Minnesota-Centric Generation Fleet Utilization
Scenarios 1 and 1a**

	S1				S1a				Δ (S1a-S1)	% Change in Dispatch
Unit Type	Total MWh Committed	Total MWh Dispatched	CF	Online CF	Total MWh Committed	Total MWh Dispatched	CF	Online CF		
Wind	113,516,032	45,298,460	40%	40%	112,894,006	45,025,066	40%	40%	(273,394)	-1%
ST Coal	76,285,799	69,984,409	65%	92%	75,904,870	70,043,841	65%	92%	59,432	0%
CT Gas	428,220	187,010	0%	44%	2,281,544	1,503,340	2%	66%	1,316,330	704%
CC	8,478,103	5,024,030	15%	59%	7,134,913	5,266,709	16%	74%	242,680	5%
Nuclear	20,209,392	20,036,836	96%	99%	19,414,416	19,246,693	93%	99%	(790,143)	-4%
Solar PV	5,175,211	2,002,869	15%	39%	5,164,167	1,998,268	15%	39%	(4,600)	0%
Conventional Hydro	1,817,899	1,225,371	30%	67%	4,110,912	1,606,155	39%	39%	380,784	31%
ST Renewable	3,965,527	3,952,032	99%	100%	2,808,218	2,783,508	70%	99%	(1,168,524)	-30%
ST Gas	184,918	82,764	6%	45%	173,067	78,786	6%	46%	(3,978)	-5%
ST Other	641,604	635,462	92%	99%	614,174	607,706	88%	99%	(27,756)	0%
IC Renewable	226,844	226,138	100%	100%	158,898	157,210	69%	99%	(68,929)	-31%
IC Gas	2,826	1,742	1%	62%	2,443	1,975	2%	81%	233	13%
Grand Total	230,932,414	148,657,123	-	-	230,662,037	148,319,353	-	-	(337,770)	0%

**Table 7-5 Comparison of Minnesota-Centric Generation Fleet Utilization
Scenarios 2 and 2a**

	S2				S2a				Δ (S2a-S2)	% Change in Dispatch
Unit Type	Total MWh Committed	Total MWh Dispatched	CF	Online CF	Total MWh Committed	Total MWh Dispatched	CF	Online CF		
Wind	157,339,652	60,467,557	38%	38%	157,943,346	60,799,827	38%	38%	332,270	1%
ST Coal	75,987,045	57,743,667	69%	76%	72,743,109	62,072,265	58%	85%	4,328,598	8%
CT Gas	388,393	175,805	0%	45%	1,241,682	867,191	1%	70%	691,387	393%
Solar PV	17,666,794	6,841,300	17%	39%	17,694,013	6,853,504	17%	39%	12,203	0%
CC	5,375,617	3,052,716	11%	57%	4,823,291	3,344,478	10%	69%	291,762	10%
Nuclear	20,207,026	20,036,836	96%	99%	19,414,416	19,246,693	93%	99%	(790,143)	-4%
Conventional Hydro	4,110,444	1,606,234	39%	39%	4,110,912	1,606,218	39%	39%	(16)	0%
ST Renewable	3,974,220	3,715,592	93%	93%	2,808,218	2,708,547	68%	96%	(1,007,045)	-27%
ST Gas	184,170	82,437	6%	45%	172,413	77,529	6%	45%	(4,908)	-6%
ST Other	641,526	632,029	92%	99%	614,174	606,931	88%	99%	(25,098)	-4%
IC Renewable	227,041	212,182	93%	93%	158,898	153,244	67%	96%	(58,938)	-28%
IC Gas	2,068	1,215	1%	59%	1,534	1,177	1%	77%	(38)	-3%
Grand Total	286,103,995	154,567,570	-	-	281,727,049	158,338,290	-	-	3,770,720	2%

7.3 Wind and Solar Curtailment

Curtailment of wind or solar generation occurs when the system is not able to accommodate all of the wind and solar generation in a given hour. The two most common reasons for curtailment are:

- The available power at particular wind or solar plant (or group of plants) is higher than the capacity of transmission lines transmitting the power to the bulk grid. This is often referred to as “local congestion”. Given that the system operates with security-constrained economic dispatch, the limitation could reflect an N-1 and/or a prior outage condition.
- The aggregate wind and solar power generation over a wide area exceeds what the grid can accommodate, even after all committed conventional power plants are dispatched at their minimum power levels and regional exports are maximized. This is sometimes referred to as a “minimum generation” condition.

In general, a small amount of curtailment is to be expected in any system with a significant level of wind and solar generation. There will be occasional operating conditions where it is economically efficient to accept a small amount of curtailment (i.e., where mitigation of that curtailment would be disproportionately expensive and not justifiable).

Table 7-6 shows annual curtailment of wind and solar energy as a percentage of the total available wind and solar energy. In all scenarios the level of curtailment in the Minnesota-Centric region is relatively small. Figure 7-8 shows annual duration curves of hourly solar curtailment. An inset in the figure shows an expanded view of the hours with the most curtailment. Curtailment occurs for only a very few hours of the year. Scenario 2 has the most curtailment of solar energy; more than 800 MW is curtailed during the worst hour. Further investigation of curtailment by plant revealed that the majority of all solar energy curtailment in Scenario 2 occurred in only two specific plants, indicating that it is likely caused by local congestion. Nonetheless, only 3% of total available solar energy is curtailed in these plants.

Figure 7-9 shows annual duration curves of hourly wind curtailment. In the Baseline and Scenario 1, there are a few hours where wind curtailment approaches 1000 MW. But for the rest of the year, curtailment is very low. In Scenario 2, there are several hours where wind curtailment exceeds 3000 MW. Figure 7-10 shows total curtailed wind energy by hour of day. In all scenarios, there is higher curtailment in nighttime hours (when many baseload generators are dispatched to their minimum output levels) than in daytime or evening hours. The trend most prominent in Scenario 2. This suggests that a portion of the overall curtailment is likely due to system-wide minimum generation conditions. This type of curtailment could be reduced by decommitting some baseload generation via economic market signals. The effectiveness of this mitigation option is illustrated by comparing Scenario 2 (coal units must-run) with Scenario 2a (economic coal commitment). Wind curtailment decreases from 2.14% to 1.60% (a reduction of 332 GWh).

Figure 7-10 also illustrates that there is some wind curtailment during daytime and evening hours, when conventional generation could likely be dispatched down if needed. This suggests that a portion of the wind curtailment is due to local transmission congestion at wind plants. In fact, further investigation revealed that the majority of wind curtailment in the Baseline and Scenario 1 occurred in just a few wind plants. This cause for curtailment could be mitigated by transmission modifications, if economically justifiable.

Table 7-6 Annual Wind and Solar Energy Curtailment

	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Wind Curtailment	0.42%	1.00%	1.59%	2.14%	1.60%
Solar Curtailment	0.09%	0.00%	0.23%	0.42%	0.24%

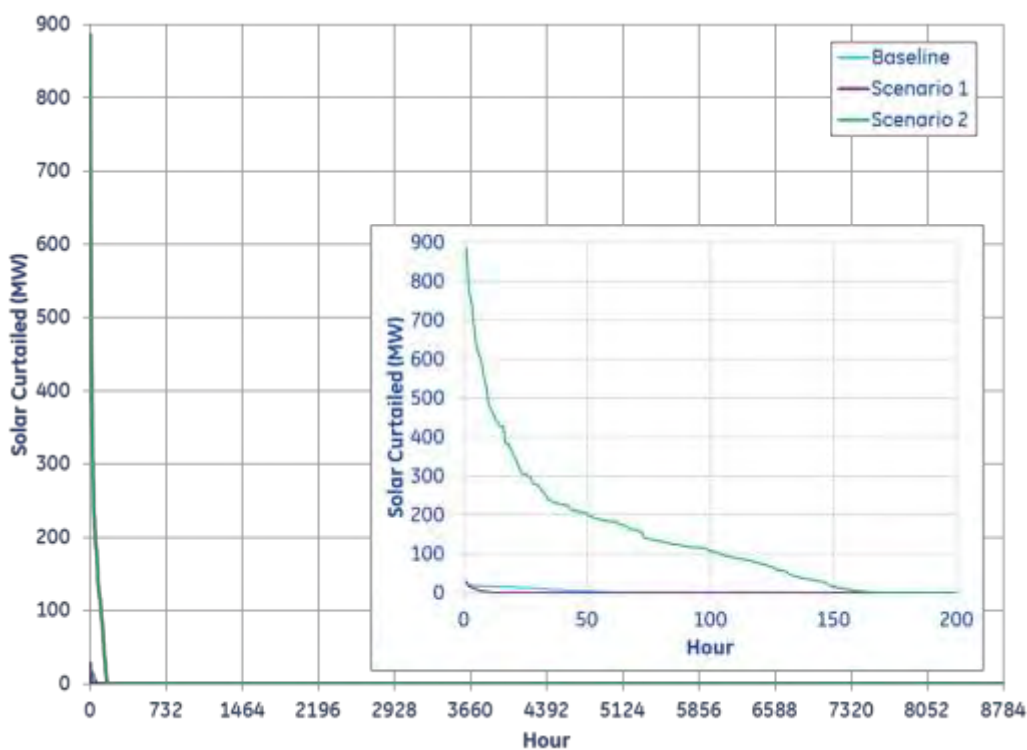


Figure 7-8 Annual Duration Curves of Solar Curtailment for Minnesota-Centric Region

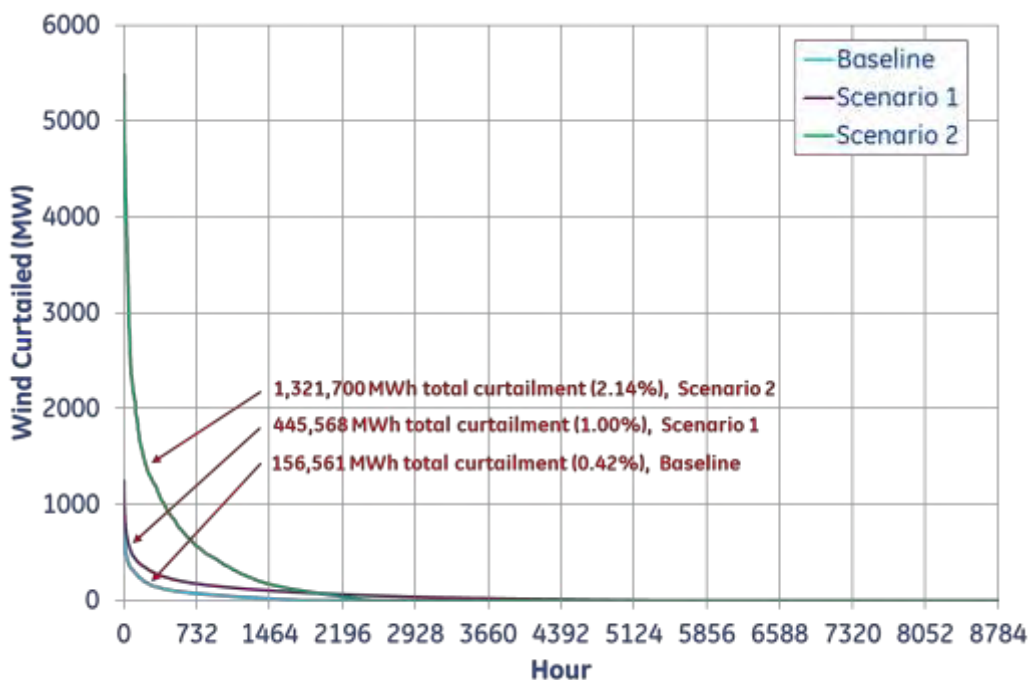


Figure 7-9 Annual Duration Curves of Wind Curtailment for Minnesota-Centric Region

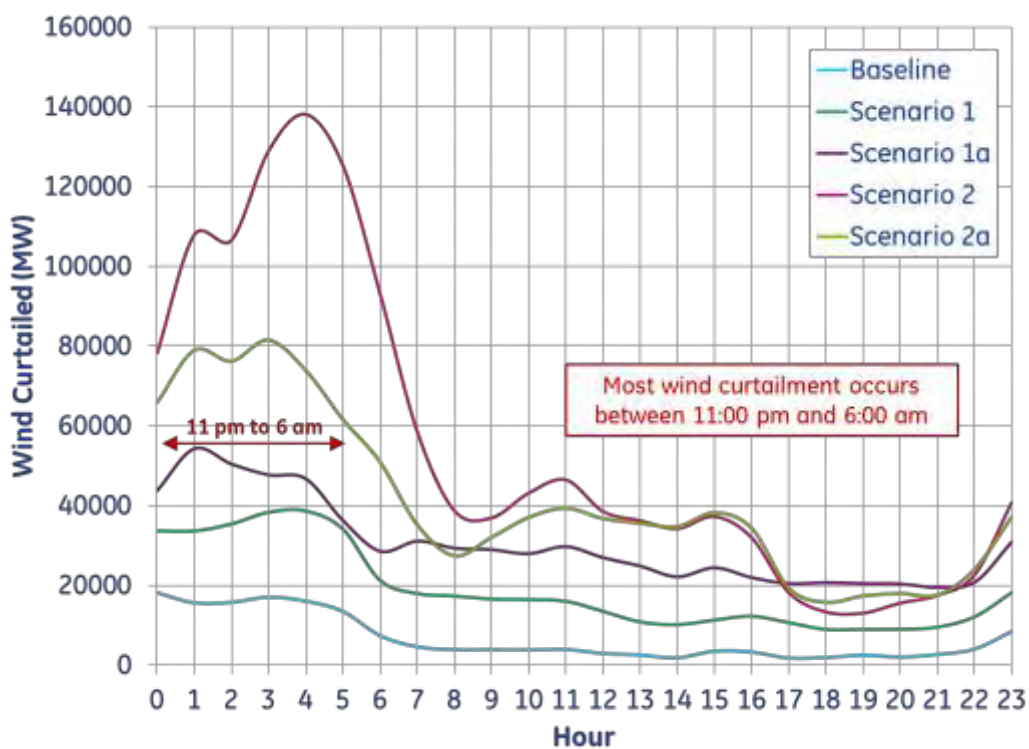


Figure 7-10 Wind Curtailment by Hour of Day for Minnesota-Centric Region

7.4 Thermal Plant Cycling

7.4.1 Coal Units

Shutting down and then restarting generating units is called “cycling”. Increased cycling of conventional generation is a natural side effect of increased wind and solar generation. Some conventional generators are shut down during periods of high wind and solar energy production, and then restarted afterwards.

Some types of units are designed to withstand multiple shutdown/startup cycles (eg., combustion turbines, hydro generators, combined cycle units). However, most coal plants were originally designed for baseload operation; that is, they were intended to operate continuously with only a few start/stop cycles in a year (mostly due to scheduled or forced outages). Increased cycling duty could impact wear and tear on these units, with corresponding impacts on maintenance requirements.

Many coal plants in MISO presently are designated by the plant’s owner to operate as “must-run” to avoid start/stop cycles that would occur if they were economically committed by the market. Figure 7-11 through Figure 7-15 illustrate the amount of cycling for coal plants in the Minnesota-Centric region.

- Figure 7-11 shows total annual starts plotted as a function of unit rating for Baseline, Scenario 1 and Scenario 2. In these scenarios, all but three coal units were assumed to be must-run, consistent with existing operating practices for those units. Hence, those units show only one start per year, following a scheduled maintenance period. The three economically committed coal units experienced from 50 to 230 starts per year.
- Figure 7-12 shows total annual starts for Scenarios 1 (with must-run assumption) and Scenario 1a (with economic commitment and forced outages). In Scenario 1a, coal units experience significantly more cycling duty than in Scenario 1. The plot also shows a general trend where smaller coal units have more annual starts than larger units.
- Figure 7-13 shows a similar comparison for Scenarios 2 and 2a. The trends are similar to the previous figure.
- Figure 7-14 shows a comparison of total annual starts for Scenarios 1a and 2a. In both scenarios, the coal unit modeling assumptions are the same (economic commitment, forced outages). The only difference is that Scenario 2a has higher wind and solar penetration than Scenario 1a. The plot shows that nearly all coal units experience higher cycling duty when the penetration of wind and solar energy increases.
- The previous figures showed total annual starts due to scheduled outages, forced outages, and economic commitment. Figure 7-15 shows only “operational” starts due to economic commitment. This figure enables a direct comparison of how increased wind and solar penetration affects the cycling duty if the coal units are economically committed by the energy market. Cycling duty increases significantly on nearly all coal units.

Note on Coal Plant Modeling: In this study, coal plants were modeled using data that was derived from the publically available Ventyx dataset, and further vetted by MISO for use in their production simulation analysis studies. Data affecting plant cycling (minimum down time, startup time, startup cost, etc) are representative values for the types of plants modeled. A more thorough analysis of coal plant cycling performance would require use of proprietary plant specific data for individual coal units, which was beyond the scope of this study.

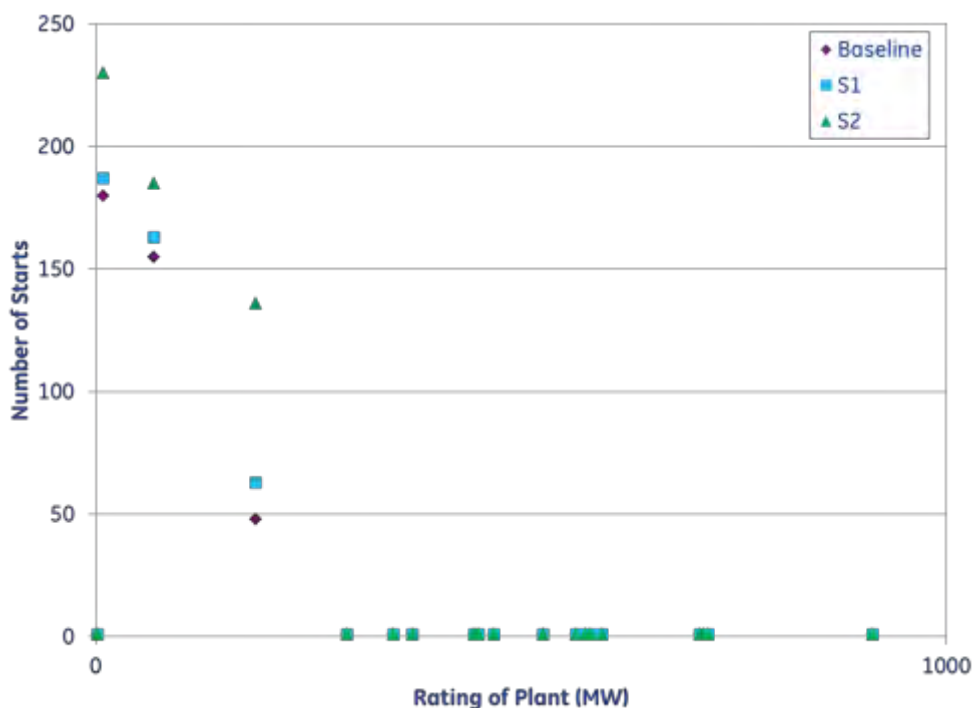


Figure 7-11 Coal Unit Total Annual Starts for Baseline, Scenario 1 and Scenario 2

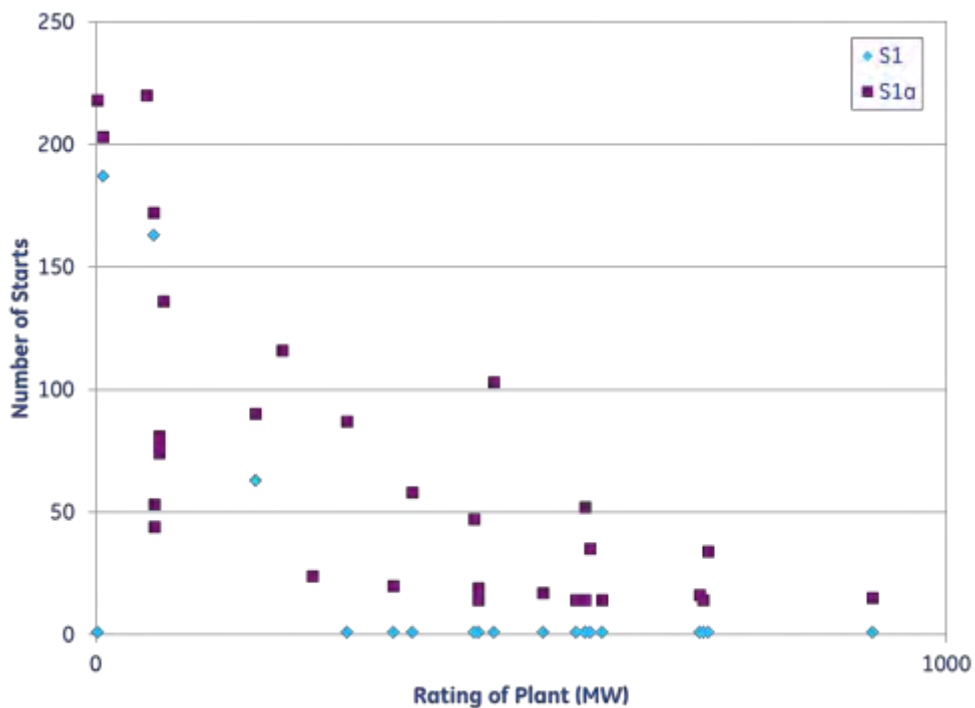


Figure 7-12 Coal Unit Total Annual Starts for Scenario 1 and Scenario 1a

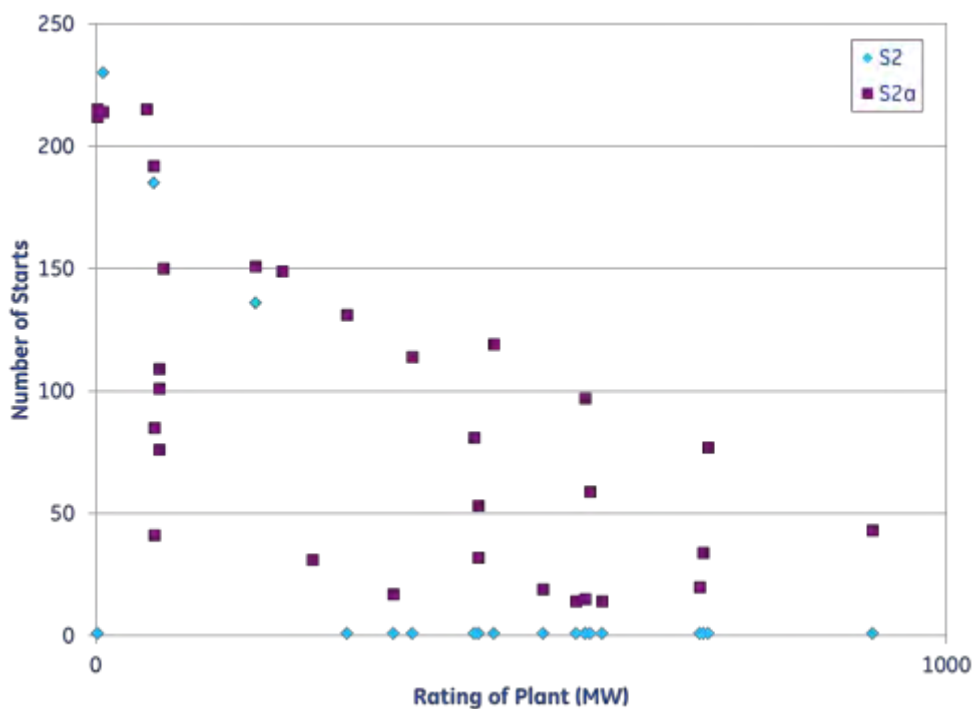


Figure 7-13 Coal Unit Total Annual Starts for Scenario 2 and Scenario 2a

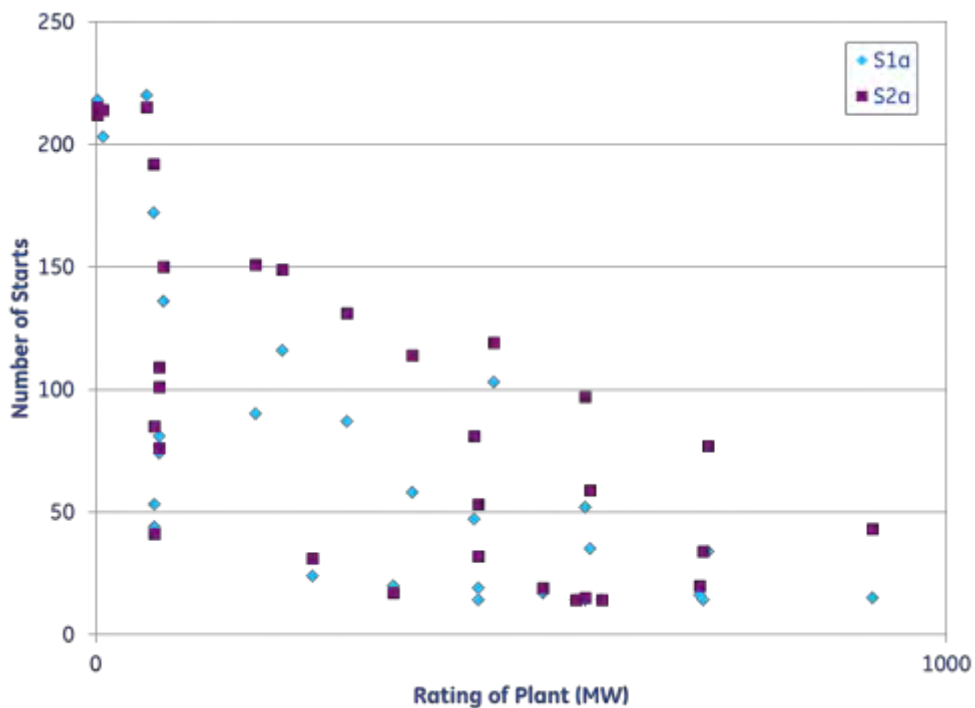


Figure 7-14 Coal Unit Total Annual Starts for Scenario 1a and Scenario 2a

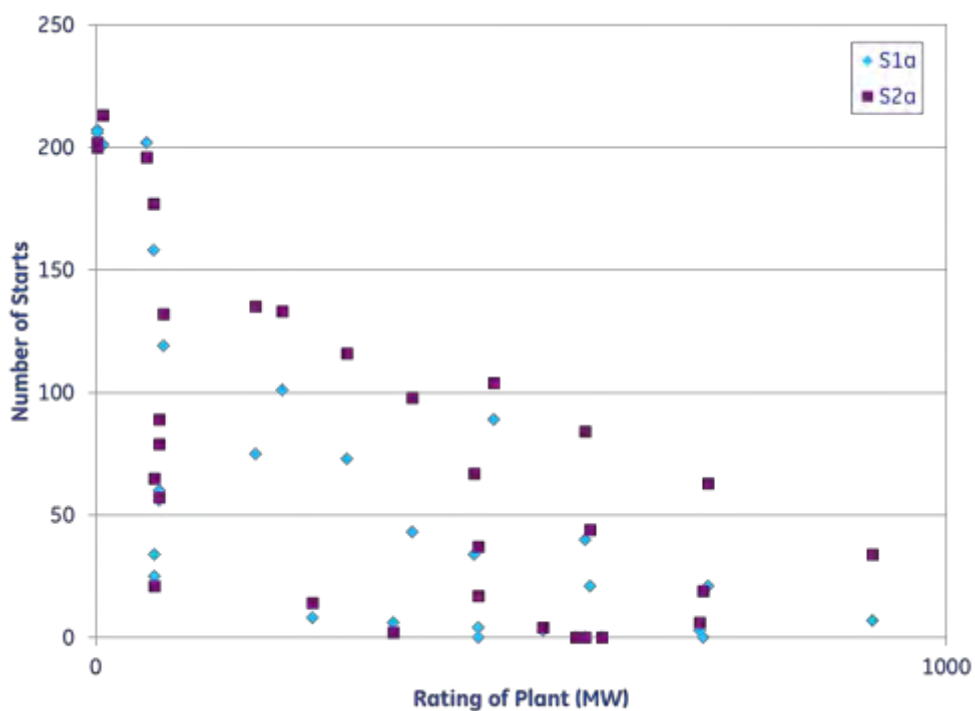


Figure 7-15 Coal Unit Annual "Operational" Starts due to Economic Commitment for Scenario 1a and Scenario 2a

7.4.2 Combined-Cycle Units

Combined-cycle (CC) units are better able to accommodate cycling duties than coal plants. Figure 7-16 is a plot of annual CC unit starts for all 5 scenarios. The data shows that some CC units in the Minnesota-Centric region experience as many as 200 start/stop cycles per year, while other units experience only a few cycles per year. In general, cycling of CC units declines slightly as wind and solar penetration increases. This decline is primarily due to a decrease in CC plant utilization as wind and solar energy increases.

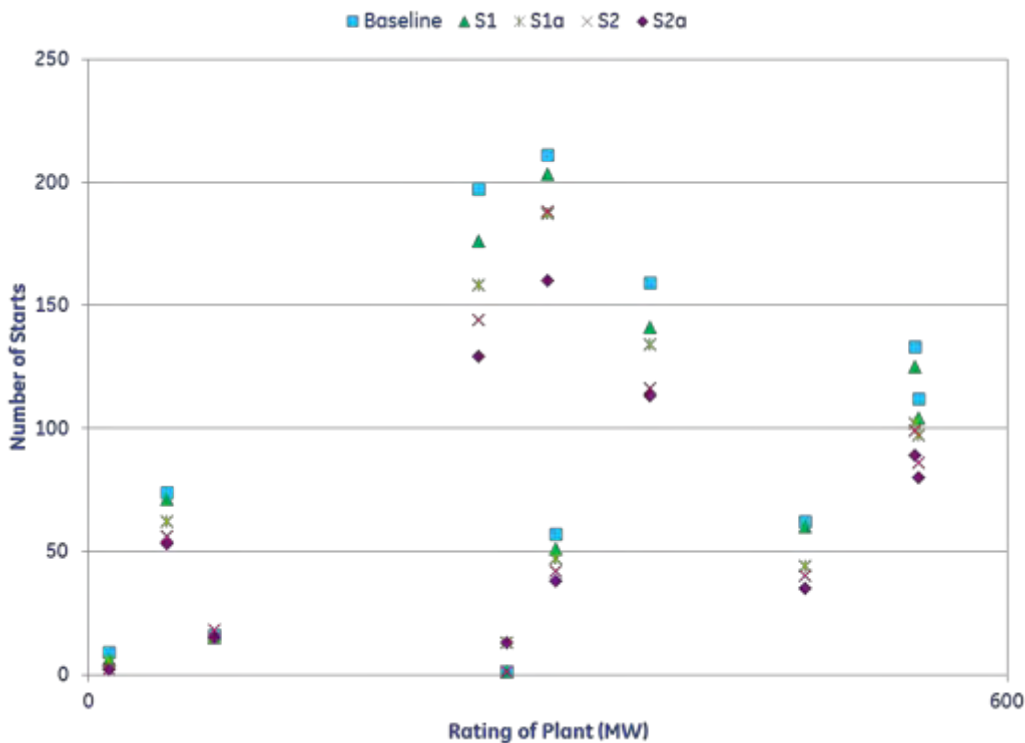


Figure 7-16 Combined-Cycle Unit Total Annual Starts for Baseline, Scenario 1, Scenario 1a, Scenario 2 and Scenario 2a

7.5 MISO Ramp-Range and Ramp-Rate Capability

Ramp-range and ramp-rate capabilities of a balancing area's conventional generation fleet are measures of its ability to accommodate the variability and uncertainty associated with wind and solar generation (i.e., the fleet's ability to follow changes in wind plant output or to compensate for forecast errors in system load and wind/solar energy production). This analysis was conducted for all of MISO Central-North, since this capability is only relevant for a balancing area.

Figure 7-17 shows range-up capability for the MISO conventional generation fleet for the Baseline, Scenario 1 and Scenario 2. Figure 7-18 shows ramp-rate up capability for the same scenarios. Ramp-range-up and ramp-rate-up capability of the MISO conventional generation fleet increases with increased penetration of wind and solar generation. Conventional generation is generally dispatched down rather than decommitted when wind and solar energy is available, which gives those generators more headroom for ramping up if needed.

Figure 7-19 shows range-down capability for the MISO conventional generation fleet for the Baseline, Scenario 1 and Scenario 2. Figure 7-20 shows ramp-rate down capability for the same scenarios. Ramp-range-down and ramp-rate-down capability of the MISO conventional generation fleet decreases with increased penetration of wind and solar generation. In Scenario 2, there are 500 hours when ramp-rate-down capability of the conventional generation fleet falls below 100 MW/min. As shown in Figure 7-21, periods of low ramp-down capability coincide with periods of high wind and solar generation (see regions within red boxes). Wind and solar generators are capable of providing additional ramp-down capability to MISO during these periods. MISO's existing Dispatchable Intermittent Resource (DIR) process already enables this for wind generators. It is anticipated that MISO would expand the DIR program to include solar plants in the future.

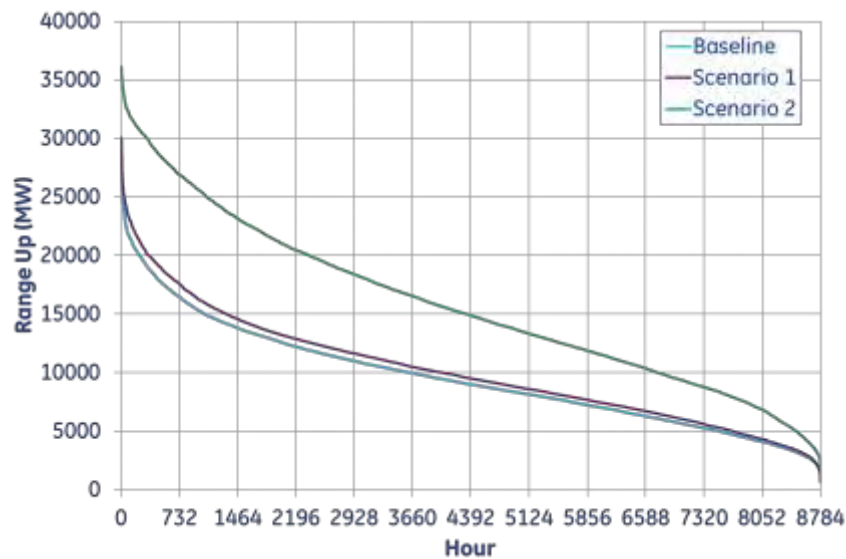


Figure 7-17 Annual Duration Curve of Range-Up Capability for Conventional Generation within MISO Central-North

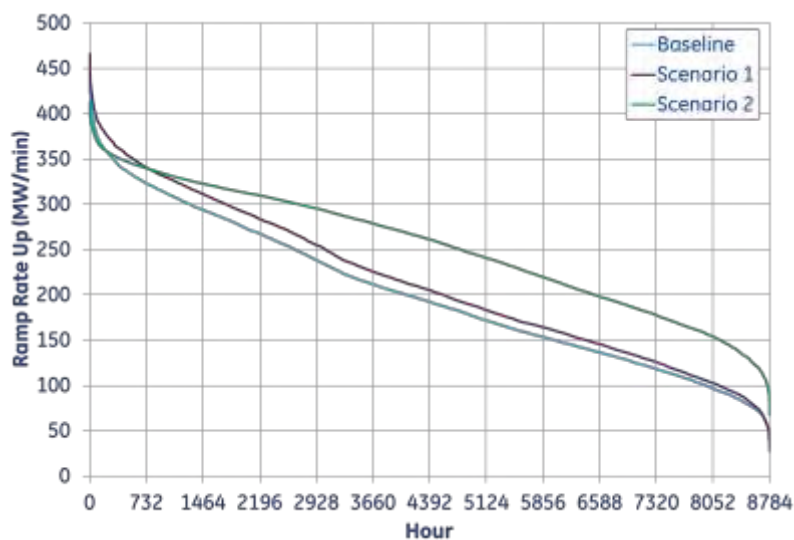


Figure 7-18 Annual Duration Curve of Ramp-Rate-Up Capability for Conventional Generation within MISO Central-North

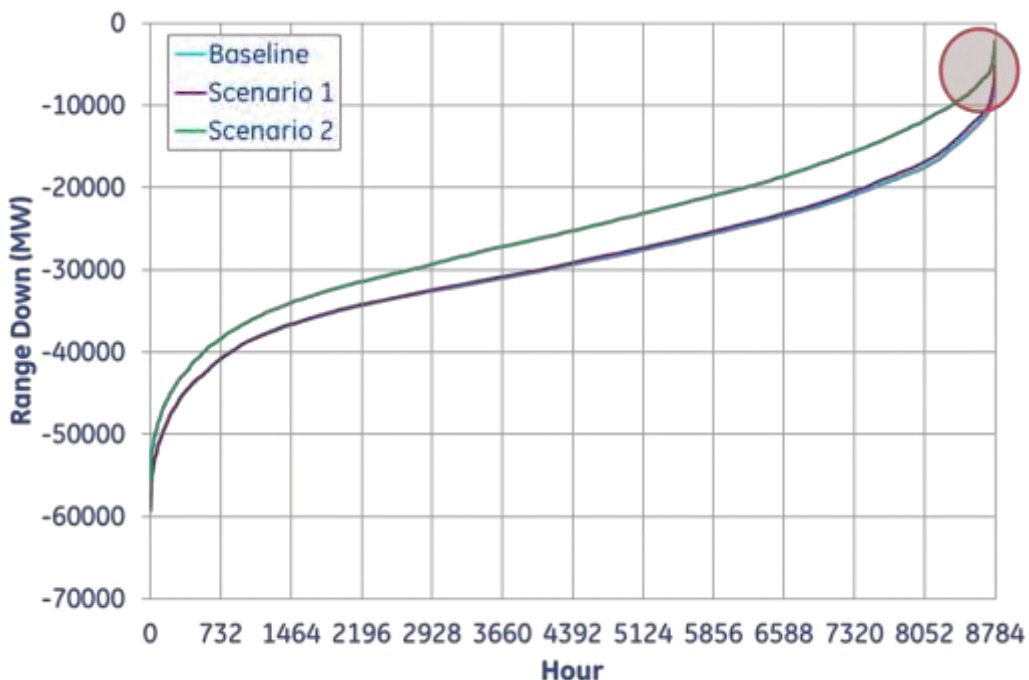


Figure 7-19 Annual Duration Curve of Range-Down Capability for Conventional Generation within MISO Central-North

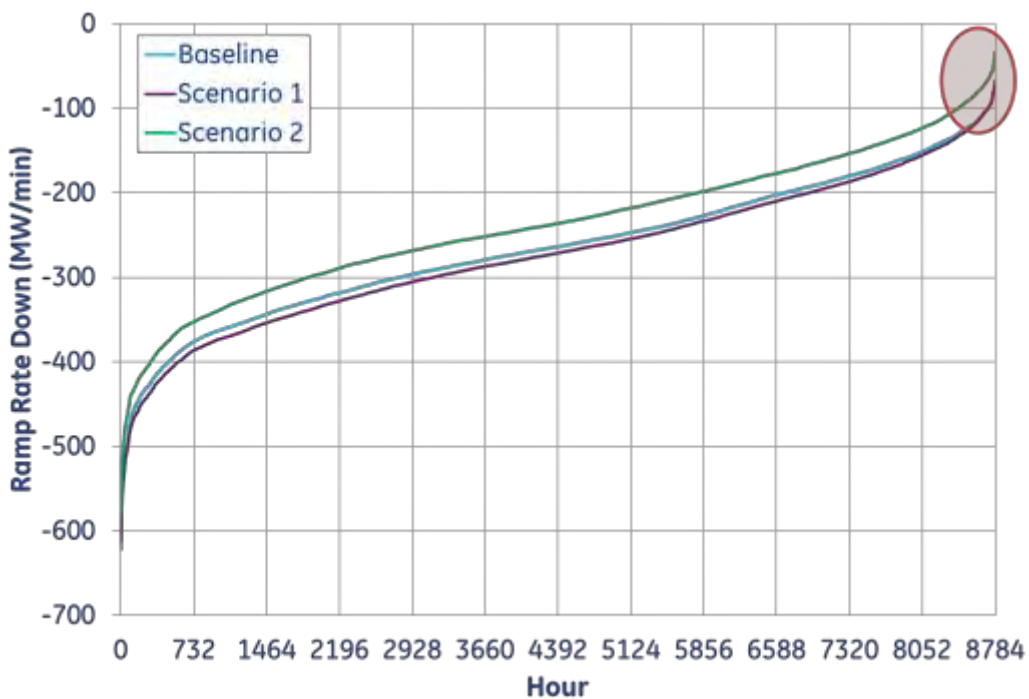


Figure 7-20 Annual Duration Curve of Ramp-Rate-Down Capability for Conventional Generation within MISO Central-North

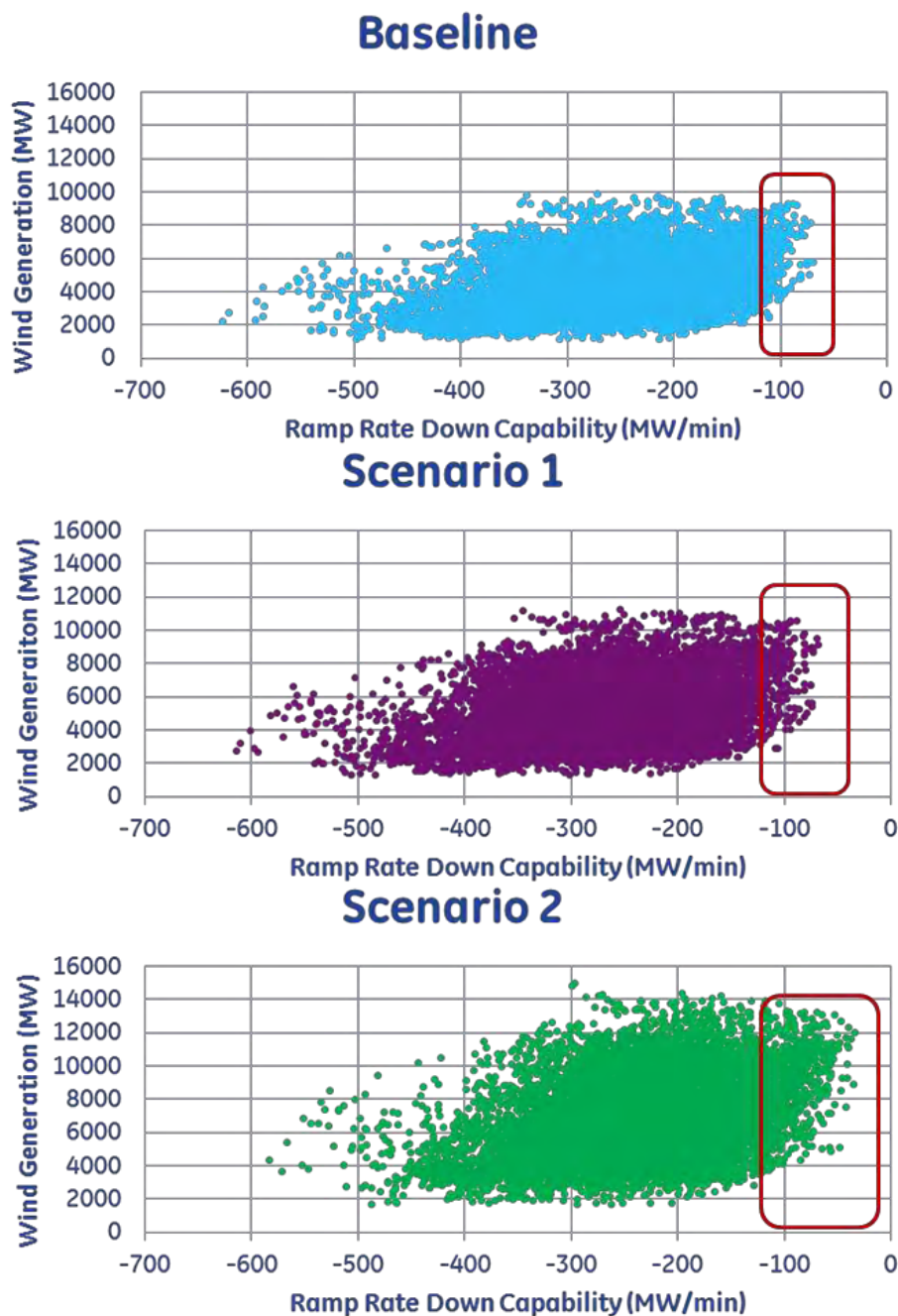


Figure 7-21 Scatter Plot of Ramp-Rate Down Capability of MISO Conventional Generation Fleet vs Wind Generation in Minnesota-Centric Region

7.6 Carbon Emissions

Table 7-7 shows total annual carbon emissions for the study scenarios. Overall, the CO₂ emissions are closely related to the amount of ST Coal committed in the system. Scenario 1a has nine more coal plants than Scenario 1. As a result, Scenario 1a has a higher level of CO₂ emissions. Similarly, Scenario 2a has higher CO₂ than Scenario 2 because of the nine additional coal plants.

Table 7-7 CO₂ Emissions for the Minnesota-Centric Region

	Baseline	S1	S1a	S2	S2a
Tons of CO₂	83,627,254	82,055,702	84,027,816	67,882,045	73,991,430
Reduction Versus Baseline (Tons CO₂)		1,571,551	(400,562)	15,745,209	9,635,823

7.7 Screening Metrics for Stability/Control Issues

The results of the production simulation analysis were screened to select challenging operating conditions for dynamic performance, and these operating points were subsequently analyzed with fault simulations in the dynamics task. This section describes the three screening metrics and the process for selecting specific system operating conditions for dynamic simulation analysis.

7.7.1 Percent Non-Synchronous Generation (% NS)

In order to assess the stability of the power system, focusing only on generation owned by the Minnesota utilities was no longer sufficient. To evaluate stability issues, it is necessary to consider all generation located within the geographic area of interest. Thus, for this metric, the definition of the Minnesota-Centric region was modified to include all generation, regardless of owner or type, within the regions shown in Figure 7-22. The Minnesota-Centric region for calculating % non-synchronous (NS) is defined by the shaded area of the figure, and includes six sub-regions; Northern Minnesota, South and Central Minnesota, Southwest Minnesota, North Dakota, South Dakota and Iowa. Based on the physical location of the generation, the % NS metric was calculated for the Minnesota-Centric region and the six sub-regions.

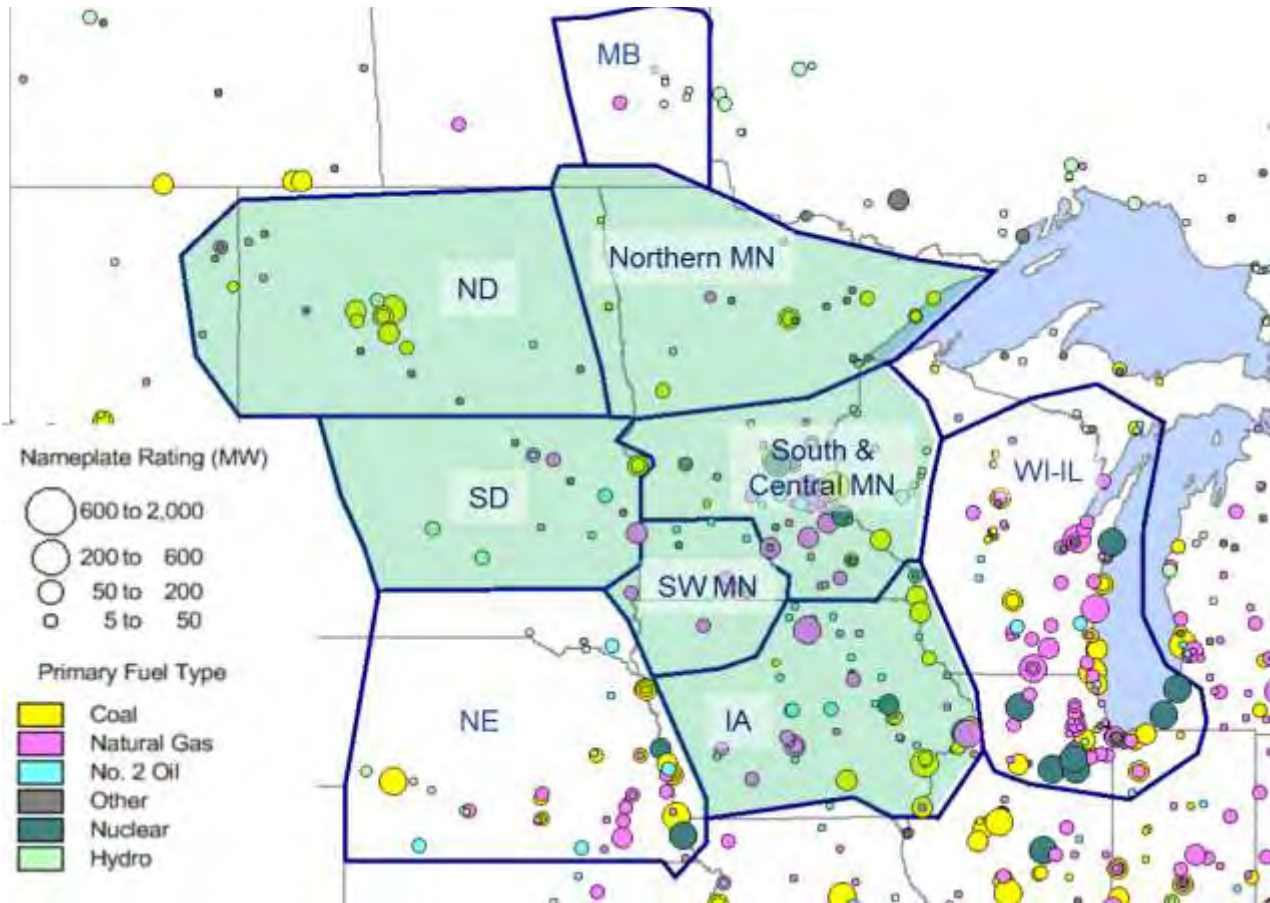


Figure 7-22 Geographic Footprint of Minnesota-Centric Region for % NS Metric

The % NS metric is the ratio of non-synchronous inverter-based generation (i.e. wind and solar) MW rating to the total generation (i.e. wind, solar and all conventional generation) MW rating within a given geographic boundary.

$$\% NS = \frac{\text{Total online wind + solar MW rating}}{\text{Total online generation MW rating}}$$

This metric is an indicator of ac system strength or weakness. Synchronous generators are pure voltage sources and therefore contribute short-circuit current and support the “strength” of the ac transmission system. Inverter-based generators do not contribute to system strength. Inverter-based generators depend on the system strength provided by synchronous machines (either generators or synchronous condensers) to operate in a stable manner. Low % NS indicates strong system conditions and high % NS indicates potentially weak system conditions. Hence, this metric can be used to identify periods of weak system conditions for further evaluation using dynamic analysis methods.

HVDC converters are also affected by system strength in a similar manner. HVDC converters have similar internal controls that can experience degraded stability under weak system conditions. However, given the scope of this study, the analysis reported here only considers weak system issues related to wind and solar generation.

7.7.2 Percent Renewable Penetration (% RE)

The % RE metric is the ratio of all wind and solar generation MW output to the total MW output of all generation (including wind and solar) within a given geographic boundary:

$$\% RE = \frac{\text{Wind} + \text{Solar MW dispatched}}{\text{Total Generation MW dispatched}}$$

This metric was applied to the Minnesota-Centric region as defined in Figure 7-1. The % RE metric was selected as it is one of the traditional metrics used to identify periods of the year where there are high levels of renewable generation supplying the load in the system, and where the dynamic performance of the overall system is more dependent on the dynamic performance of the wind and solar resources.

7.7.3 Transmission Interface Loading

This metric was used to identify periods of high loading on three interfaces that are important to the dynamic performance of the Minnesota region. High loading on these interfaces stresses the overall transmission system, and provides appropriate operating conditions for testing system resilience to transmission system faults.

North Dakota Export (NDEX): This interface consisted of 23 lines that provided most of the power transfer out of the North Dakota sub-region. The geographic representation of this interface is seen in Figure 7-23.



Figure 7-23 NDEX Transmission Interface

Buffalo Ridge Outlet: This interface consisted of four selected transmission lines that transfer energy out of the wind rich Buffalo Ridge region. The physical location of the lines is seen in Figure 7-24.

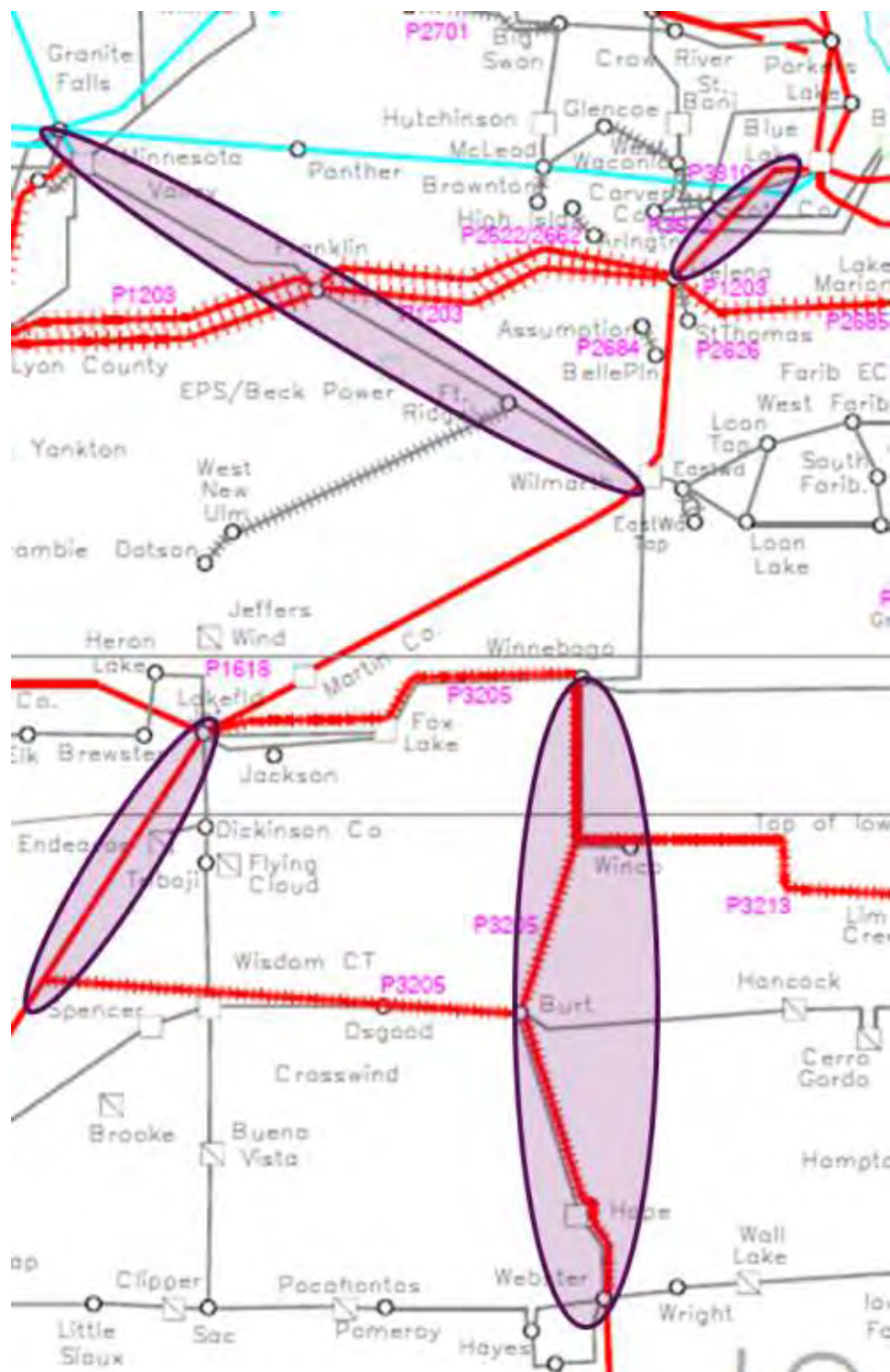


Figure 7-24 Buffalo Ridge Outlet Lines

Minnesota-Wisconsin Export (MWEX): This interface monitored the flows across three major transmission lines from Minnesota into Wisconsin (see Figure 7-25).

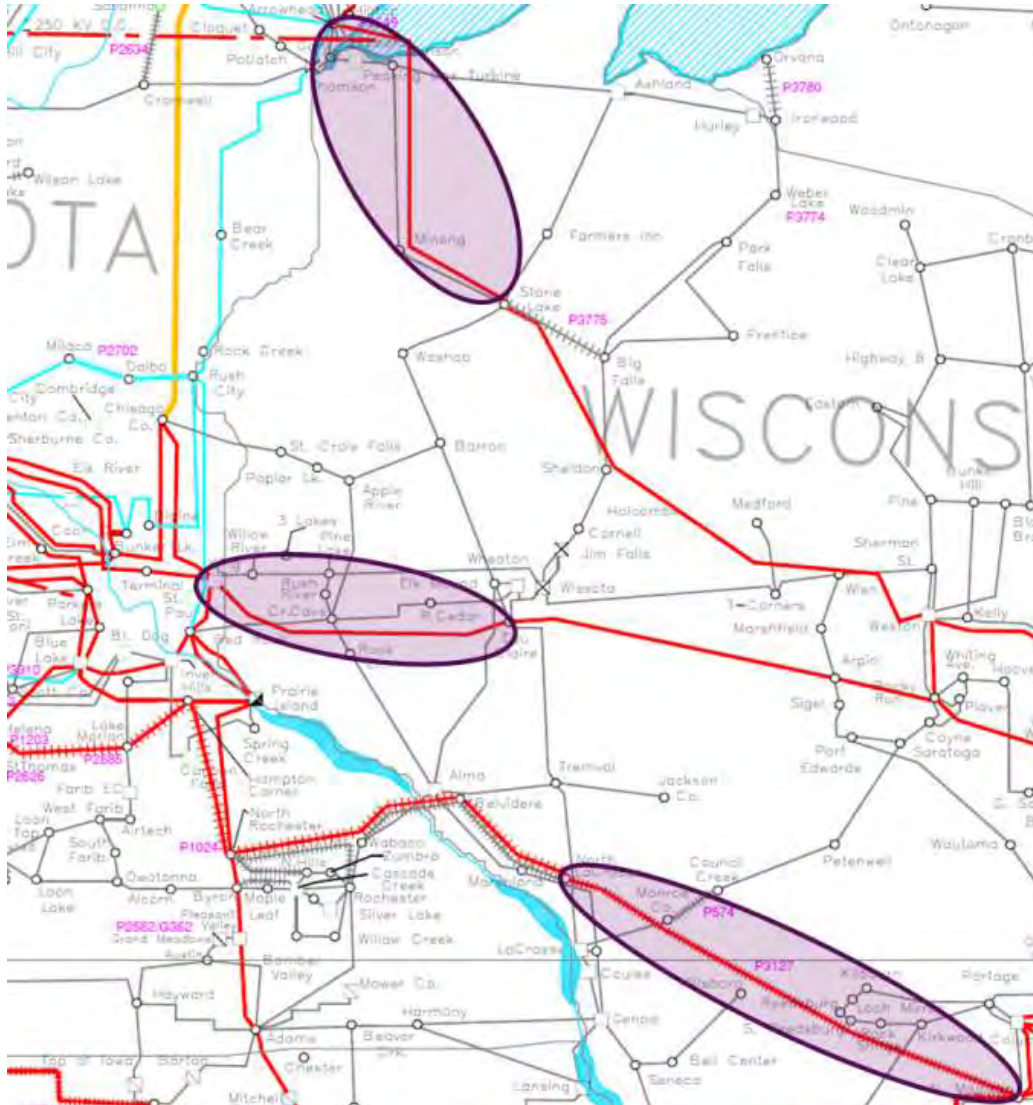


Figure 7-25 MWEX Transmission Interface

7.7.4 Analysis of Percent Non-Synchronous Generation

The % NS metric was calculated for each hour of the year and plotted as duration curves for the Minnesota-Centric region as well as its six subregions (per Figure 7-22). The results are plotted in Figure 7-26 through Figure 7-30.

The % NS varies greatly across the five scenarios. The general trend is that % NS gradually increases from the Baseline (Figure 7-26) to Scenario 1 (Figure 7-27) and finally to Scenario 2 (Figure 7-29). This correlates with the increased wind and solar generation displacing some of the conventional synchronous generation in the region. With lower levels of conventional plant online, the % NS values increase on average.

Different trends are observed when comparing Scenario 1 with Scenario 1a (Figure 7-28). In Scenario 1a, there were nine additional coal plants (existing plants not retired), all of the coal plants were given more operational flexibility (i.e., not must-run), and the forced outage rates of the conventional plants were enforced. As a result, the tails of the duration curves show significant differences. The periods of higher % NS and lower % NS both increase. These same trends can be observed by comparing Scenario 2 with Scenario 2a in Figure 7-30. Table 7-8 provides the maxima and minima of % NS for each of the scenarios studied.

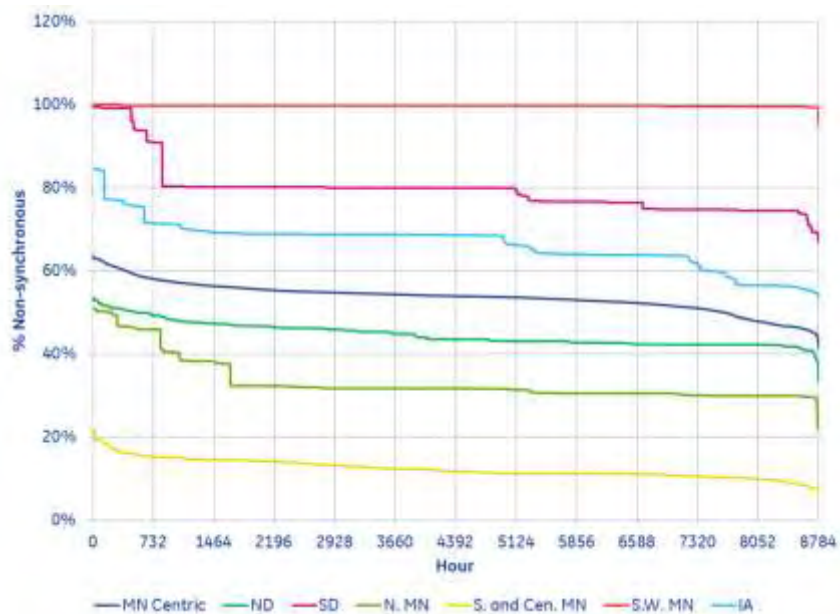


Figure 7-26 Baseline % NS Duration Curves

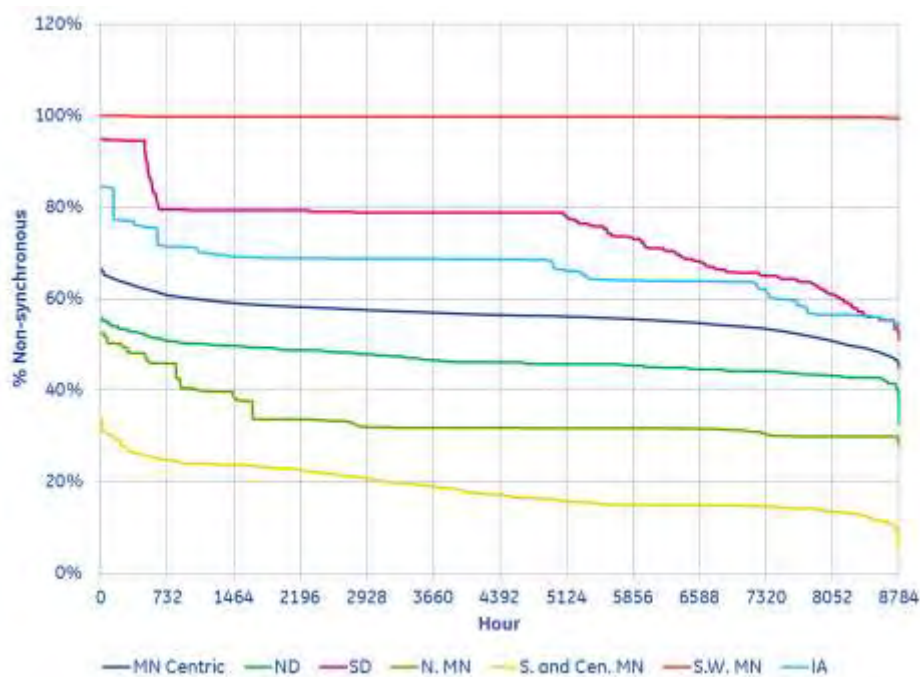


Figure 7-27 Scenario 1 % NS Duration Curves

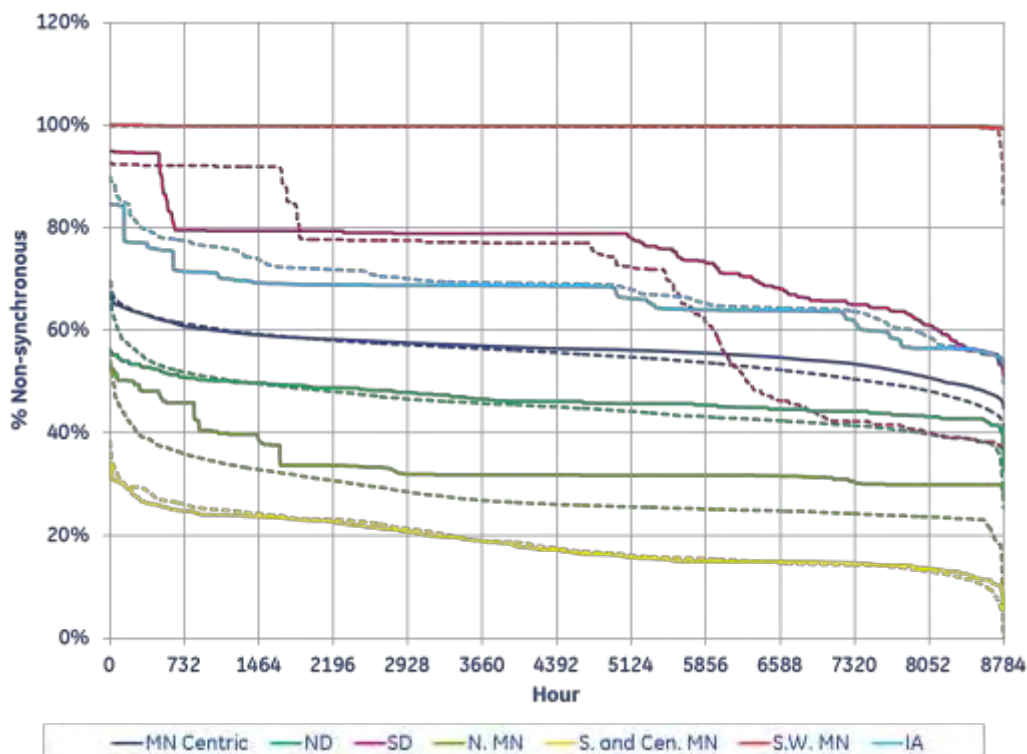


Figure 7-28 Scenario 1 (solid) and 1a (dashed) % NS Duration Curves

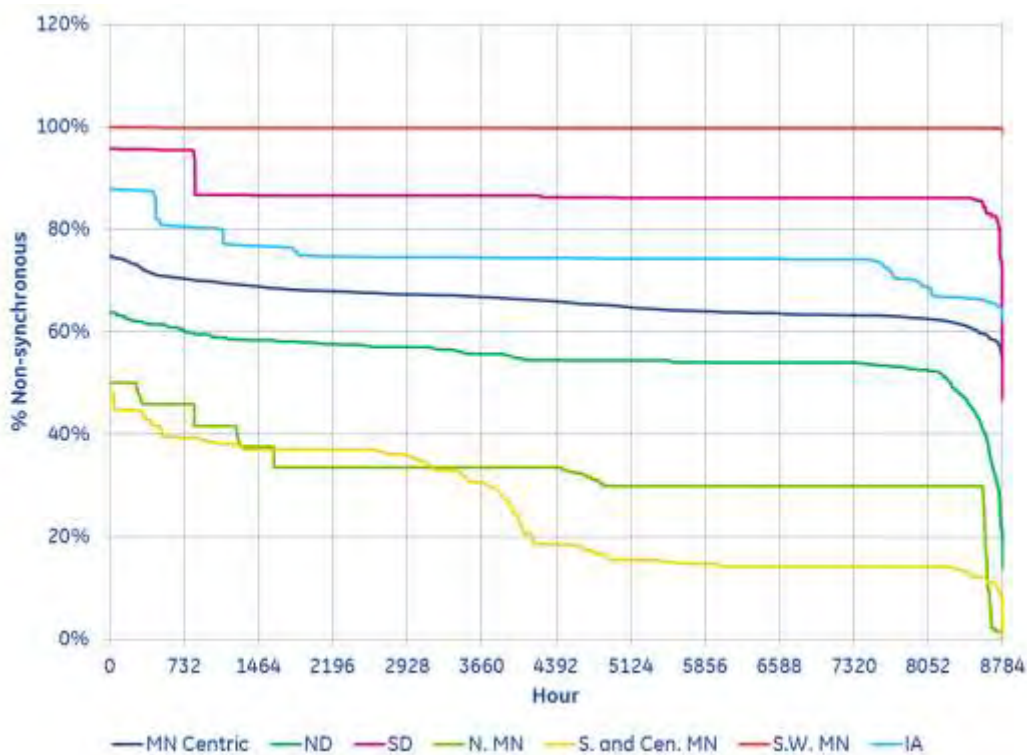


Figure 7-29 Scenario 2 % NS Duration Curves

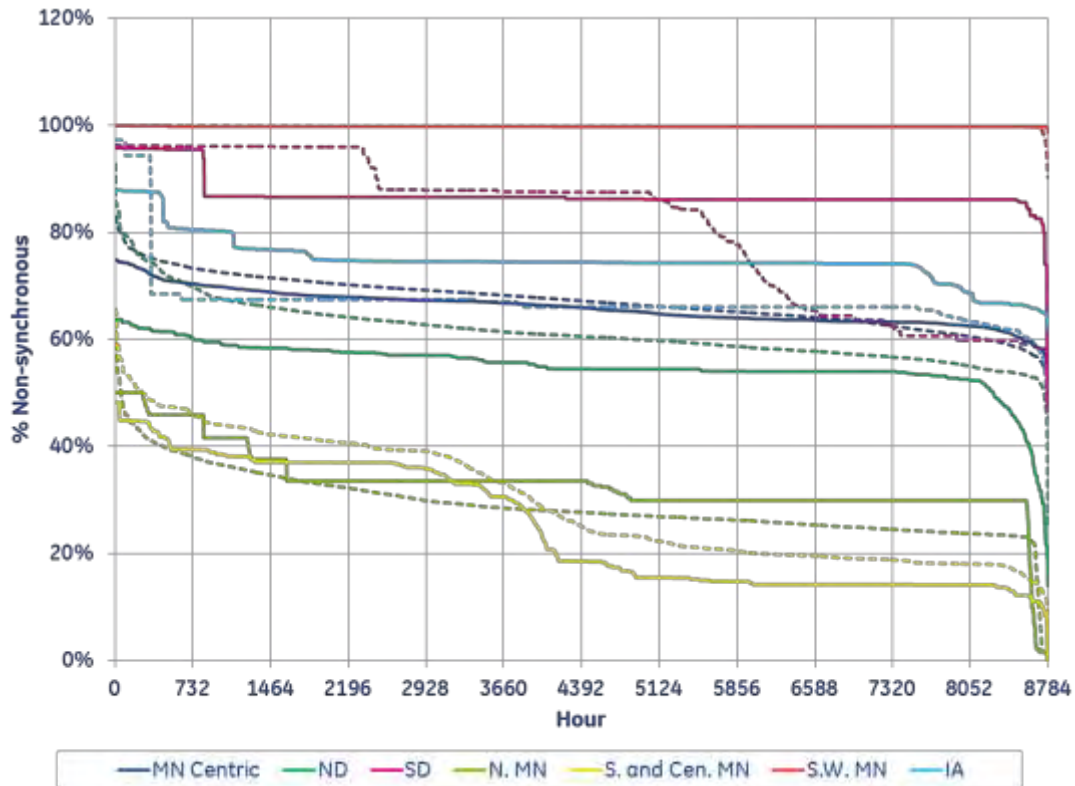


Figure 7-30 Scenario 2 (solid) and 2a (dashed) % NS Duration Curves

Table 7-8 Maximum and Minimum % NS Values

Scenario	Minnesota Centric	Northern Minnesota	South & Central Minnesota	Southwest Minnesota	North Dakota	South Dakota	Iowa
Baseline	Max: 64% Min: 42%	Max: 51% Min: 22%	Max: 22% Min: 6%	Max: 100% Min: 95%	Max: 53% Min: 34%	Max: 99% Min: 67%	Max: 85% Min: 53%
Scenario 1	Max: 67% Min: 45%	Max: 53% Min: 28%	Max: 34% Min: 6%	Max: 100% Min: 99%	Max: 56% Min: 33%	Max: 95% Min: 51%	Max: 85% Min: 54%
Scenario 1a	Max: 70% Min: 40%	Max: 56% Min: 0%	Max: 38% Min: 0%	Max: 100% Min: 85%	Max: 70% Min: 25%	Max: 93% Min: 37%	Max: 90% Min: 50%
Scenario 2	Max: 75% Min: 52%	Max: 50% Min: 0%	Max: 48% Min: 0%	Max: 100% Min: 99%	Max: 64% Min: 14%	Max: 96% Min: 47%	Max: 88% Min: 62%
Scenario 2a	Max: 83% Min: 52%	Max: 62% Min: 0%	Max: 66% Min: 9%	Max: 100% Min: 90%	Max: 93% Min: 25%	Max: 96% Min: 45%	Max: 97% Min: 44%

7.7.5 Percent Renewable Penetration Analysis

Figure 7-31 shows duration curves of the % RE metric for the Minnesota Centric region for all five scenarios. The general trend from Baseline to Scenario 1 to Scenario 2 is an increase in the % RE penetration as the wind and solar levels increase and conventional generation is backed down to accommodate the increased output.

Scenario 1a has a slightly higher % RE than Scenario 1, consistent with the change in % NS between the two scenarios. Conversely, Scenario 2a has a significantly lower % RE than Scenario 2. This is contrary to % NS which is higher for Scenario 2a than Scenario 2. This is primarily related to the changes in modeling assumptions for the coal units. In Scenario 2a where coal units are economically committed, fewer MW of ST Coal and CC generation are committed over the course of the year, but when a plant is committed it is run at a higher capacity factor. This behavior is documented in Section 7.4, where the transition from Scenario 2 to Scenario 2a, sees fewer TWh of ST Coal and CC generation being committed, but the dispatched TWh increasing.

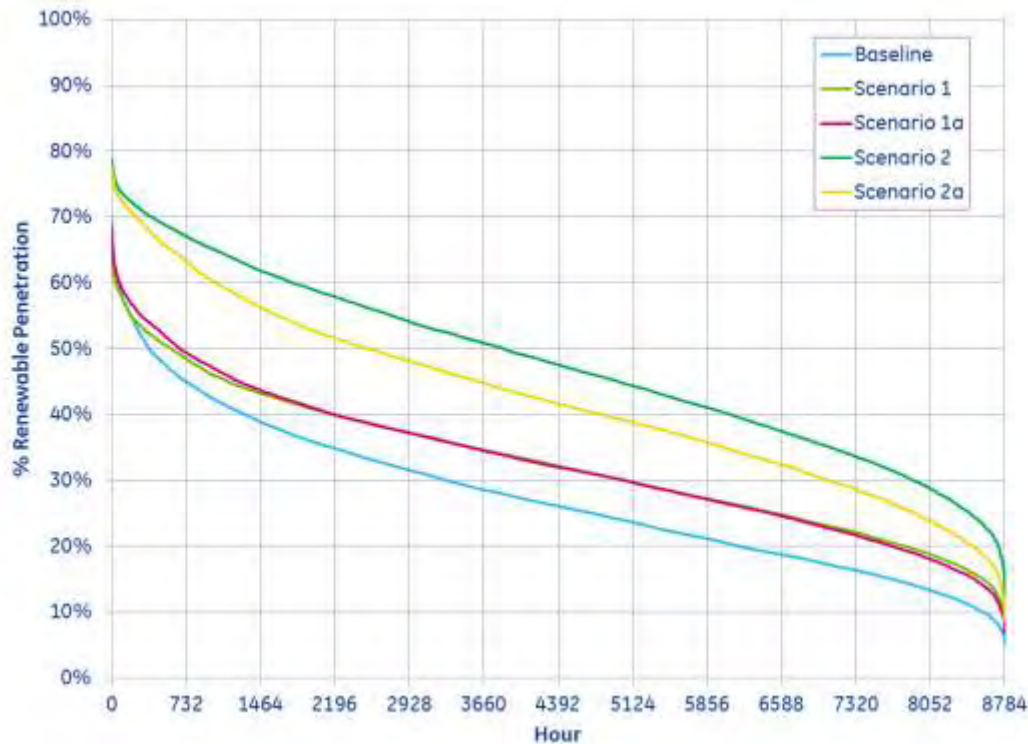


Figure 7-31 % RE Penetration for the Minnesota-Centric Region

7.7.6 Transmission Interface Loading

During periods of high transmission interface loading, the grid could be more vulnerable to power swings after transmission system faults.

In Figure 7-32 through Figure 7-34, the interface loading duration curves are compared for Scenario 1 and Scenario 1a. These were the only two scenarios that were analyzed as they were the only ones that were studied for the dynamic analysis.

For each of the three interfaces an increase in interface loading is observed as the dispatch and commitment moves from Scenario 1 to Scenario 1a for the NDEX (Figure 7-32) and MWEX (Figure 7-34) interfaces. This is due to the fact that there is an overall increase in the ST Coal in the sub-regions close to the interfaces. Both NDEX and MWEX see increases due to additional coal energy in North Dakota and Northern Minnesota from plants that were retired in Scenario 1 but were part of the ST Coal fleet in Scenario 1a. The Buffalo Ridge Outlet flow (Figure 7-33) is nearly the same in Scenarios 1 and 1a because these lines are primarily loaded with wind and solar power, which is nearly the same in both scenarios.

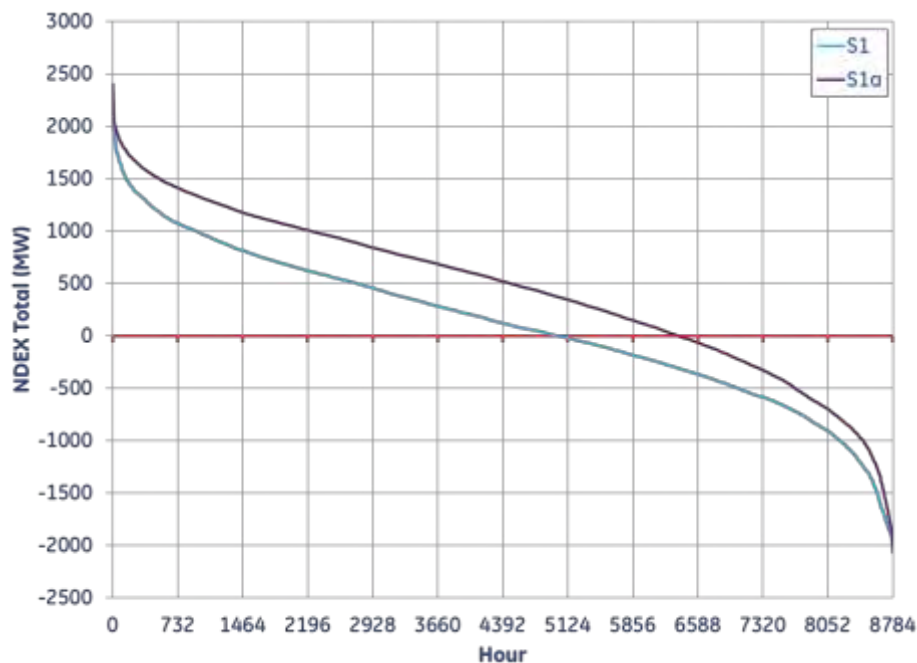


Figure 7-32 NDEX Total Loading for Scenario 1 and Scenario 1a

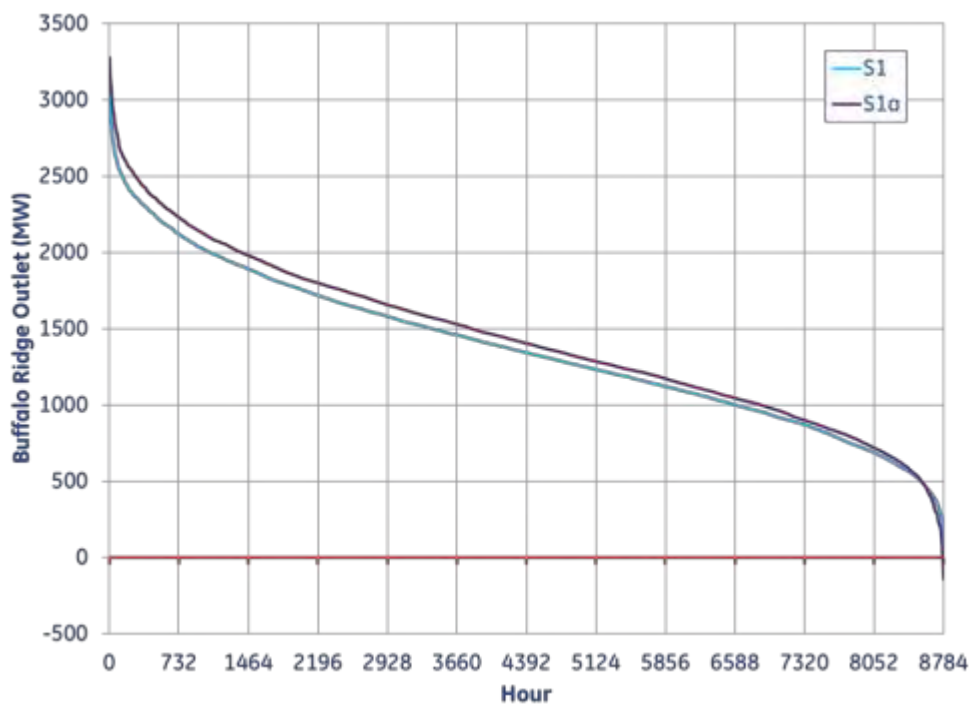


Figure 7-33 Buffalo Ridge Outlet Loading for Scenario 1 and Scenario 1a

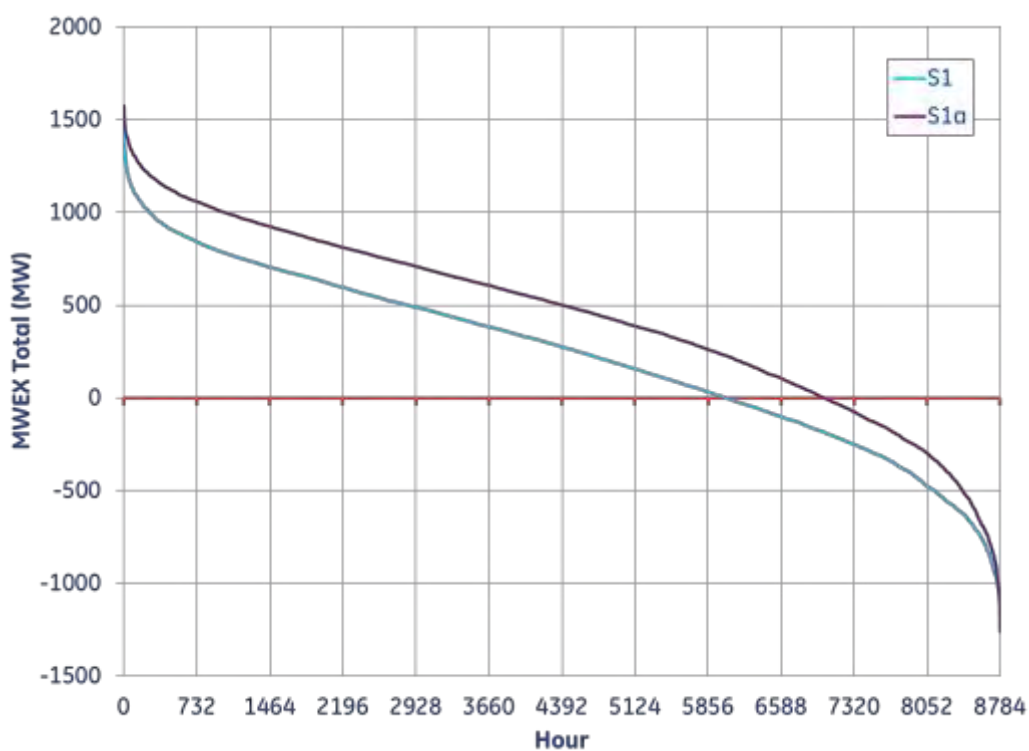


Figure 7-34 MWEX Total Loading for Scenario 1 and Scenario 1a

7.8 Selection of Operating Conditions for Dynamic Analysis

Using the three metrics described in the previous section, seven stability cases were selected for each of the two studied scenarios, Scenario 1 and Scenario 1a, for a total of 14 cases. First they were screened based on the Scenario 1 data followed by a secondary screening and adjustment if necessary based on the Scenario 1a data.

This section describes the process of using the metrics to identify the stability cases. The goal of the screen process was to filter down the 8784 hours of operation from the production simulation results into small groups of hours with common operating conditions that would facilitate in building a commitment and dispatch in the appropriate power flow case.

The first metric used to screen for stability cases was the % NS measure. The following process was used to identify appropriate cases to feed into the dynamic stability assessment.

1. The hourly % NS data for the scenario is plotted against the load duration curve for the Minnesota-Centric region. The load curve is segmented into 3 regions (peak, shoulder, light) that correspond to the power flow cases (Figure 7-35). This provided system load levels that would serve as filters for the next step.

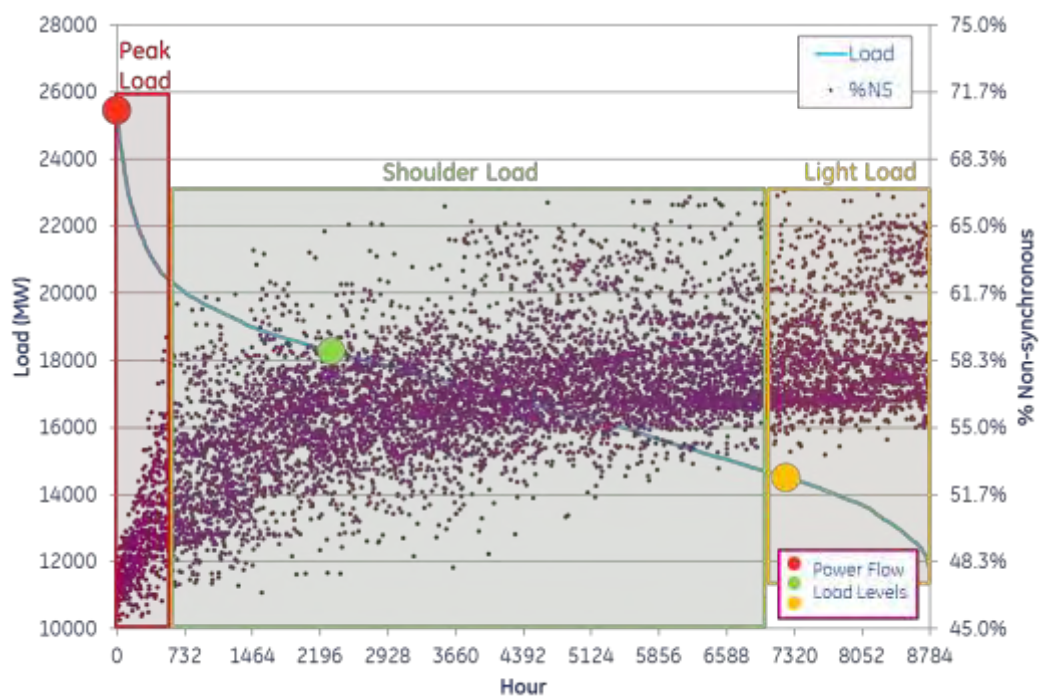


Figure 7-35 Load Duration Curve and % NS for the Minnesota-Centric Region

2. Next, the load and corresponding hourly % NS values were plotted chronologically (as in Figure 7-36). Once again, loading levels that corresponded to the power flow cases (peak, shoulder, light) were identified and used to refine the loading windows in hours with similar characteristics.

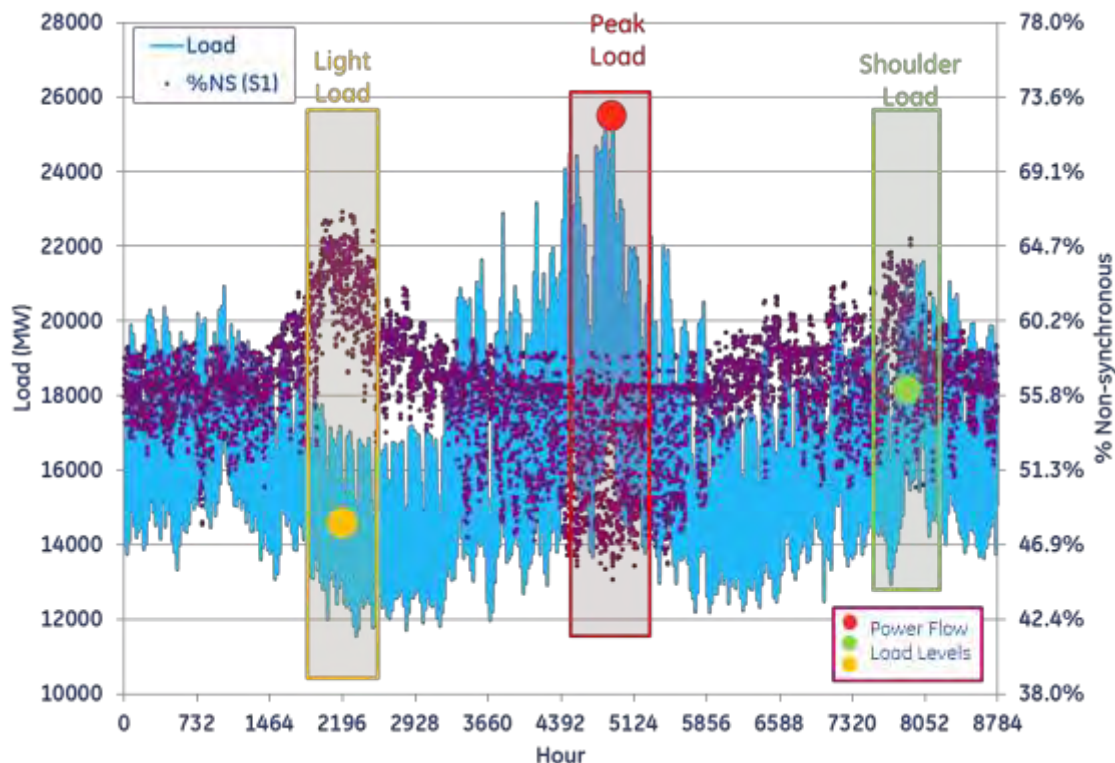


Figure 7-36 Chronological Load and % NS for the Minnesota-Centric Region

3. To identify a group of hours with similar operating conditions, the data was filter by time of year (fall), system load level (shoulder) and highest % NS (>55%). The result was 118 hours that satisfied the criteria (Figure 7-37).

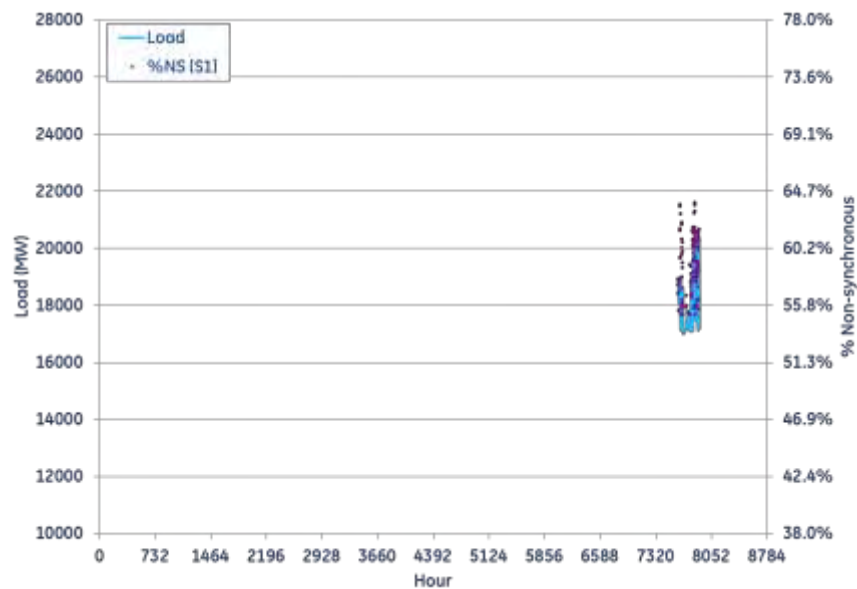


Figure 7-37 Filtered Load and % NS to the Fall Shoulder-Load Window

4. These 118 hours were then sorted by time of day to ensure that the hours with online solar (daytime hours) were captured and allowed for consistent hours in the commitment and dispatch (Figure 7-38). This resulted in 15 hours where the commitment and dispatch had very high % NS levels during a very small window.

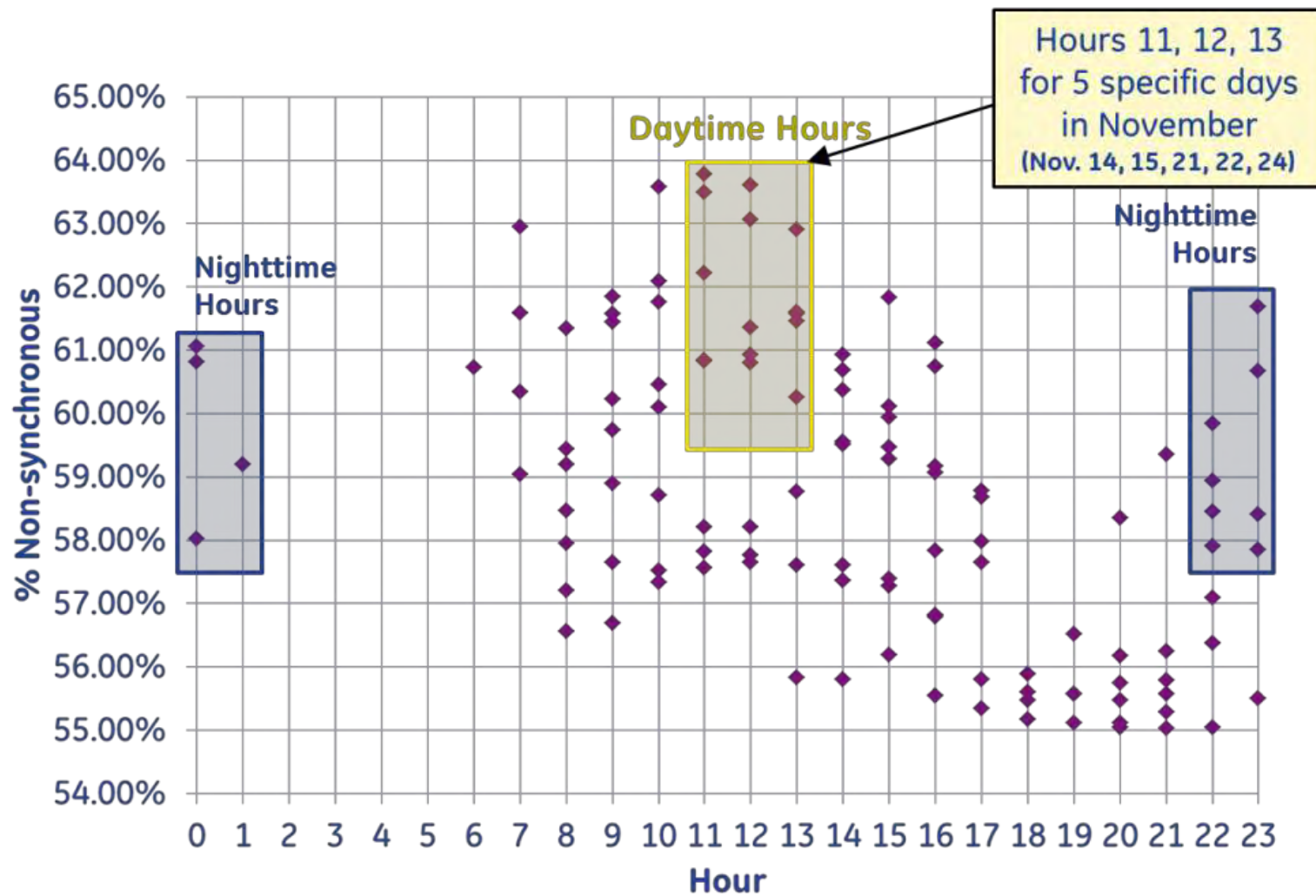


Figure 7-38 Further Filter Fall Shoulder Hours for Scenario 1 Stability Analysis

Through this same methodology a further two stability cases were selected for the % NS case that corresponded to the peak load and light load periods and a high % RE case that corresponded to a light load period. Three additional cases were selected using the interface loading metric for a total of seven Scenario 1 stability cases (Table 7-9).

Table 7-9 Stability Cases for Scenario 1

Case	Criteria	Load	Day / Night	Notes
1	High % NS	Shoulder	Day	55% - 64% NS, 5 days in Nov., 11am - 1pm
2	High % NS	Light	Night	%NS > 60%, April 2-8, 12am-7am
3	High % NS	Peak	Day	46% - 51% NS, July 21-27, 2pm-7pm
4	High % RE Penetration	Light	Night	%RE > 55%, Avg. 71% Oct. 1, 5-7, 12am - 7am
5	High Transmission Loading NDEX	Shoulder	Night	Path Loading>1900 MW, Oct. 25 - 30
6	High Transmission Loading Buffalo Ridge Outlet	Shoulder	Night	Path Loading>2800 MW, May 20 - 22
7	High Transmission Loading MWEX	Light	Day	Path Loading>1400 MW, June 8, 11, 14

Next, the seven cases were re-screened to ensure that the commitment and dispatch windows still corresponded to the limits of the defined stability metrics. For the interface loading metric, the three cases for Scenario 1, corresponded with the new data for Scenario 1a for the NDEX (Figure 7-39), Buffalo Ridge Outlet (Figure 7-40) and the MWEX (Figure 7-41) interfaces.

For the NDEX interface, the period highlighted in Figure 7-39, indicates an interface loading greater than 1900 MW. For the Buffalo Ridge Outlet interface, the highlighted period in Figure 7-40 indicates an interface loading greater than 2800 MW. Finally, for the MWEX interface, the highlighted period in Figure 7-41 indicates an interface loading greater than 1400 MW. These values are based on the highest observed flows on the interfaces and do not correlate with a particular stability limit for the system.

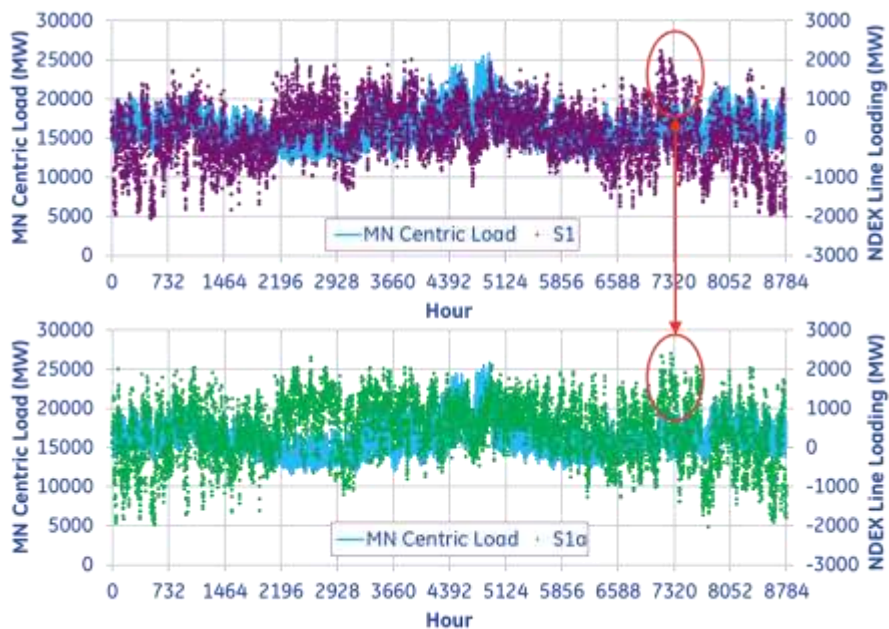


Figure 7-39 NDEX Interface Screening for Scenario 1 and Scenario 1a

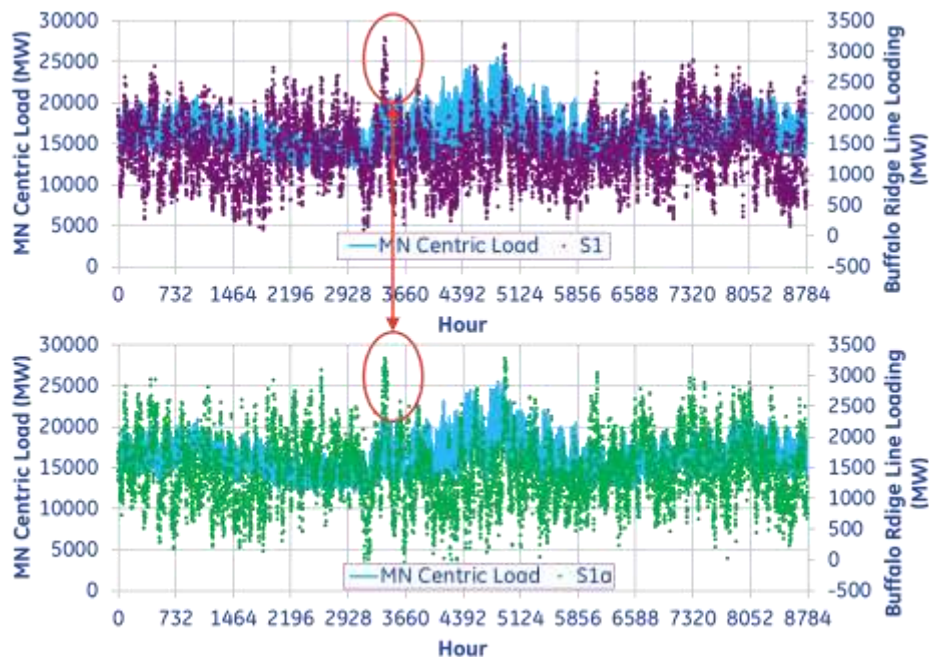


Figure 7-40 Buffalo Ridge Outlet Interface Screening for Scenario 1 and Scenario 1a

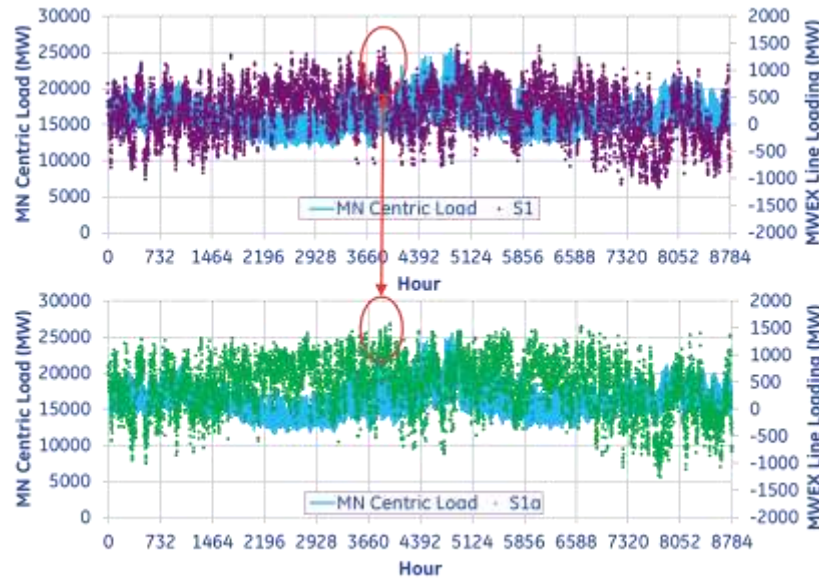


Figure 7-41 MWEX Interface Screening for Scenario 1 and Scenario 1a

For the remaining four cases, Cases 1, 3 and 4 showed close correlation between Scenario 1 and Scenario 1a. As a result, the dispatches between these cases were compared and the power flow for the cases was adjusted according to the new Scenario 1a commitment and dispatch. Case 2 was the only case that required an adjustment of the stability window.

As seen in Figure 7-42, a new peak in % NS for the light load case was observed around hour 3000 in Scenario 1a. As such, the methodology described previously in this section was applied and new commitment and dispatch for Case 2 was developed based on the Scenario 1a data. Overall, the new commitment and dispatch from Scenario 1a for Case 2 resulted in a net increase of 1288 MW of non-synchronous generation commitments.

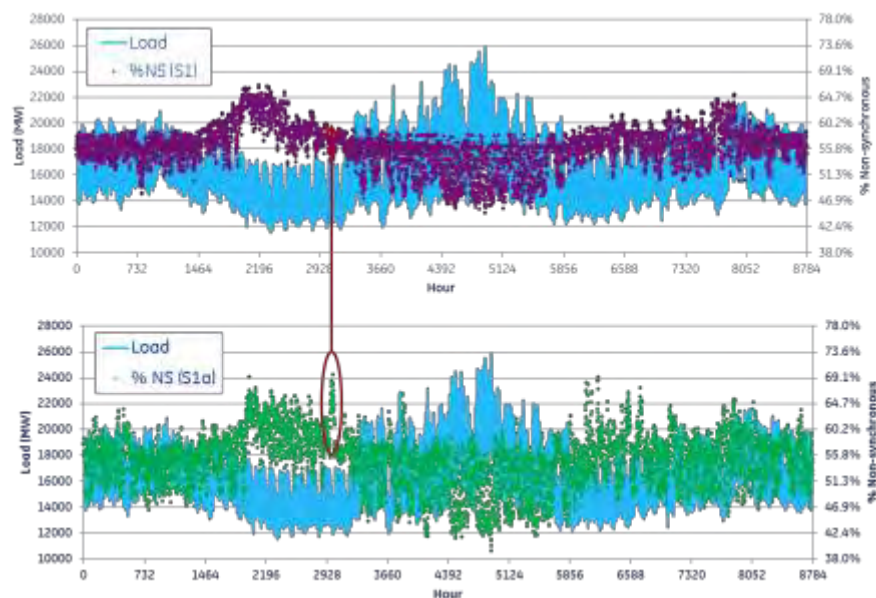


Figure 7-42 Case 2 Stability Screening for Scenario 1 and Scenario 1a

8 DYNAMIC SIMULATION RESULTS

The objective of this analysis was to test the dynamic performance of the system under the most challenging system conditions observed in the scenario S1 and S1a production simulation analysis with respect to renewable generation.

The dynamic study cases developed for the S1 analysis represent a full spectrum of operating conditions cover light load, shoulder load and peak load. Every wind plant was on line for each of the study cases. All PV plants and distributed PV were on line for daytime cases and off line for nighttime cases. Renewable generation levels were set based on the production simulation results for the condition being simulated.

The cases cover a wide range of synchronous generation commitment and dispatch due to the different screening metrics used to select challenging hours. In addition, two different production simulation runs were used (S1 and S1a), with their different assumptions on must-run status, generation retirement and forced outages. The study cases represent hours with lower than average commitment and dispatch of synchronous generation, giving a high percentage of renewable energy and non-synchronous generation on line. These cases also stress several critical interfaces and transfer paths with high Manitoba Hydro exports and high Buffalo Ridge Outlet, NDEX and MWEX interface flows.

8.1 Dynamic Performance Study Conditions

Power flow study cases were developed for the seven different system conditions described in the previous section. The commitment and dispatch of all generators (both conventional and renewable) throughout and outside of MISO was set based on unit operation during the corresponding hours in the production simulation analysis. Conventional units that were on line less than 25% of the sample hours were decommitted in the power flow case. Conventional units on line more than 25% of the sample hours were committed and operated at or above their average dispatch for those hours. Renewable generation was committed and dispatched based on the average of the sample hours from production simulation.

These dynamic study cases, listed in Table 8-1, include three light load, three shoulder load and one peak load condition. Case 4 was used to test high MWEX transfers at light load. The table lists the case number from the production simulation analysis, the stability case name, the selection criteria, load level and comments. The notes include the percentage of non-synchronous generation (%NS) and percentage of renewable energy (%RE) for the Minnesota-centric region. These are calculated as:

$$\%NS = \frac{\text{Total online wind} + \text{Solar MW rating}}{\text{Total online generation MW rating}}$$

and

$$\%RE = \frac{\text{Wind} + \text{Solar MW dispatched}}{\text{Total Generation MW dispatched}}$$

The notes also include information on high transmission loading where applicable. Note that analysis of high MWEX loading (case 7, light load) was performed using the light load case with high percentage of renewable energy (case 4), since this case has very high MWEX loading. Additional contingencies on the highest loaded MWEX lines were simulated to focus on the impact of high transfers.

Table 8-1 Stability Case Description

Case	Name	Criteria	Load	Notes
1	S1_SH_D01	High % NS	Shoulder	49% NS Generation 37% Renewable Energy
2	S1_LL_D02	High % NS	Light	48% NS Generation 36% Renewable Energy
3	S1_PK_D03	High % NS	Peak	37% NS Generation 21% Renewable Energy
4	S1_LL_D04	High % RE Penetration	Light	47% NS Generation 40% Renewable Energy
5	S1_SH_D05	High Transmission Loading NDEX	Shoulder	47% NS Generation 37% Renewable Energy 2334 MW NDEX Loading
6	S1_SH_D06	High Transmission Loading Buffalo Ridge Outlet	Shoulder	48% NS Generation 41% Renewable Energy SW Minn Renewables at 95% Pmax
7	S1_LL_D04*	High Transmission Loading MWEX	Light	47% NS Generation 40% Renewable Energy 2424 MW MWEX Loading

*** Note:** Case 4 has MWEX loading above 1400 MW (max value from production simulation). The impact of MWEX loading was tested using this case, subject to additional contingencies on MWEX lines.

The MW dispatch of all Minnesota-centric generation is illustrated in Figure 8-1. This bar graph shows the total on-line generation in MW by type for each of the six study cases. Figure 8-2 shows the same information, but in the form of pie charts of the percentage of generation by type. This is similar to the percent renewable energy measure (%RE) used for the production simulation screening. The dispatches are shown in order of increasing generation, from light load to shoulder load to peak load.

The reporting of %RE for the stability cases is lower than that reported in the production simulation analysis due to differences in the grouping of generation. However, the generation dispatch for each case matches the average dispatch for the selected time period in the production analysis.

Figure 8-3 shows the total MVA of committed Minnesota-centric generation by type for the six study cases. This measure sums the rated MVA of each on-line unit. It does not consider the MW output of the machine, only if the unit is on-line or not. Figure 8-4 presents the same information, but groups the generation as synchronous and inverter-based. The inverter-based generation is made up of all wind, solar PV and distributed PV since most of this generation is power electronic inverter based. Inverter-based generation is also referred to as non-synchronous. This figure shows the rated MVA of each type as a percentage of total on-line MVA. This measure is similar to the percent non-synchronous generation (%NS) used for production simulation screening. Note that HVDC converter stations are not included in the calculation of percent non-synchronous.

The measure of %NS for the light and shoulder load study cases is between 47% and 48% across the Minnesota-centric area. The measure of %NS for the peak load case is 37%. These measures are lower than the %NS reported in the production simulation analysis. This difference is due to three factors:

1. These calculations are based on the sum of rated MVA of on-line generators, where the production simulation analysis is based on the sum of rated MW. In general, a synchronous machine will have a higher MVA rating than a wind or PV plant with the same MW capability. This will lower the measure of percent non-synchronous.
2. There are over 2700 MVA of synchronous units that were not included in the %NS calculations for production simulation, but are included in the calculations for stability analysis. This includes the two Quad Cities nuclear units (1068 MVA each).
3. Over 4600 MW of the renewable generation added for Baseline and S1 scenarios was located at buses outside the Minnesota-centric footprint. These are modeled and included in the stability analysis but not accounted for in calculating the %NS measure.

While the calculation of %NS differs between the production simulation and stability cases, the actual commitment/dispatch in the stability simulations matches that of the production simulation.

Figure 8-5 shows the percentage of on-line synchronous and non-synchronous generation (based on rated MVA) for each of the six regions in the Minnesota-centric footprint for each study case. The same information is shown in Figure 8-6, but shown as total MVA. SW Minnesota is nearly 100% non-synchronous generation for all of the dispatches. South Dakota averages over 60% NS, and is as high as 80% NS for the two light load cases. Iowa and North Dakota have between 40% NS and 50% NS across the cases, and Northern, Central and South Minnesota have 20% or less %NS.

Figure 8-7 shows the dynamic reactive reserves from synchronous, non-synchronous and static var compensator SVC (labeled "Other") sources for each region. The dynamic reactive reserves are calculated as the difference in the maximum reactive capability minus the reactive output of a unit. This calculation does not include mechanically switched capacitors.

The dynamic reactive reserves closely follow the on-line MVA for each region. The renewable generation provides a significant portion of the dynamic reactive reserves in Iowa, North and South Dakota. All of the reactive reserves in SW Minnesota are from renewable generation sources. The ± 60 MVar SVC at Lake Yankton was not included in this analysis.

The reactive reserves in Northern Minnesota are from synchronous generators and the Forbes SVC. The SVC is critical to supporting imports from Manitoba Hydro (MH). One objective in developing the power flow cases was to maintain over 350 MVAR of dynamic reserves from the SVC. This was achieved using the mechanically switched shunt capacitors associated with the SVC.

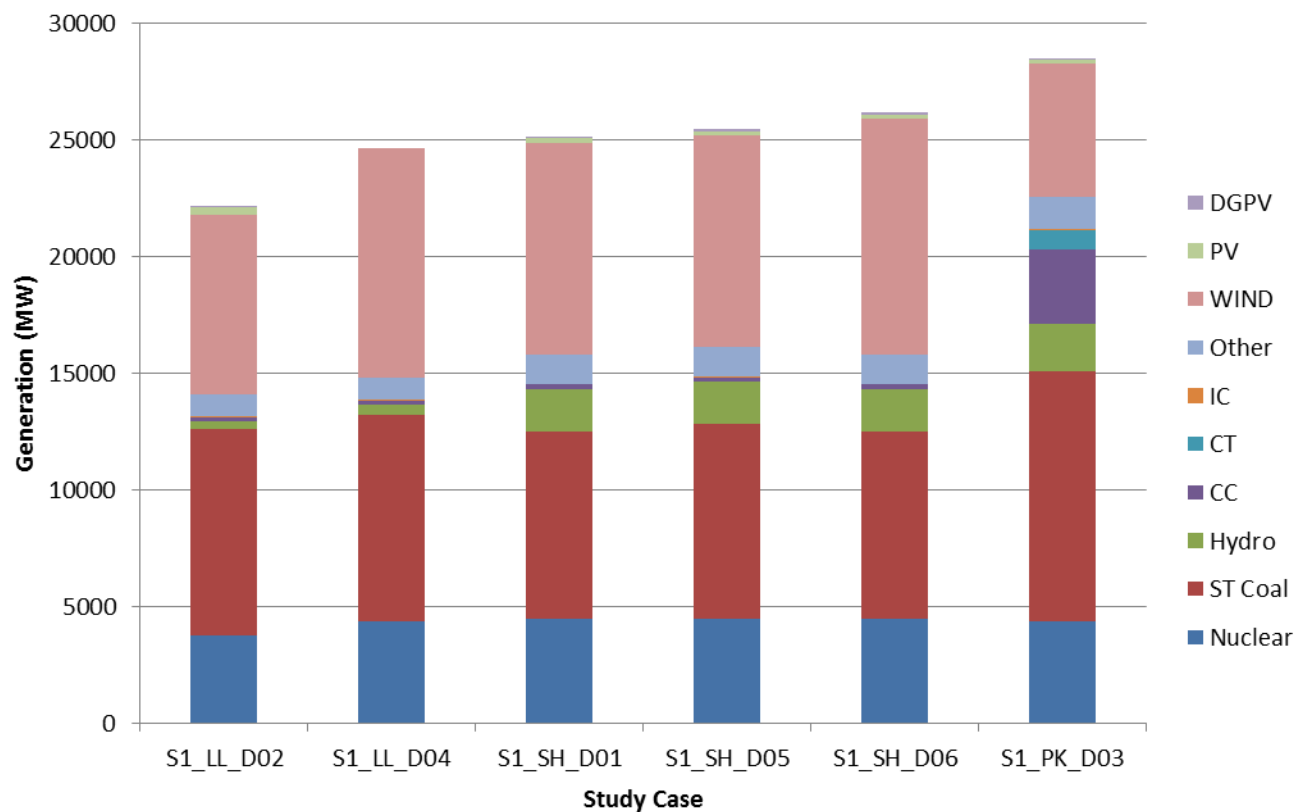


Figure 8-1 Minnesota Centric Dispatch (MW) By Unit Type

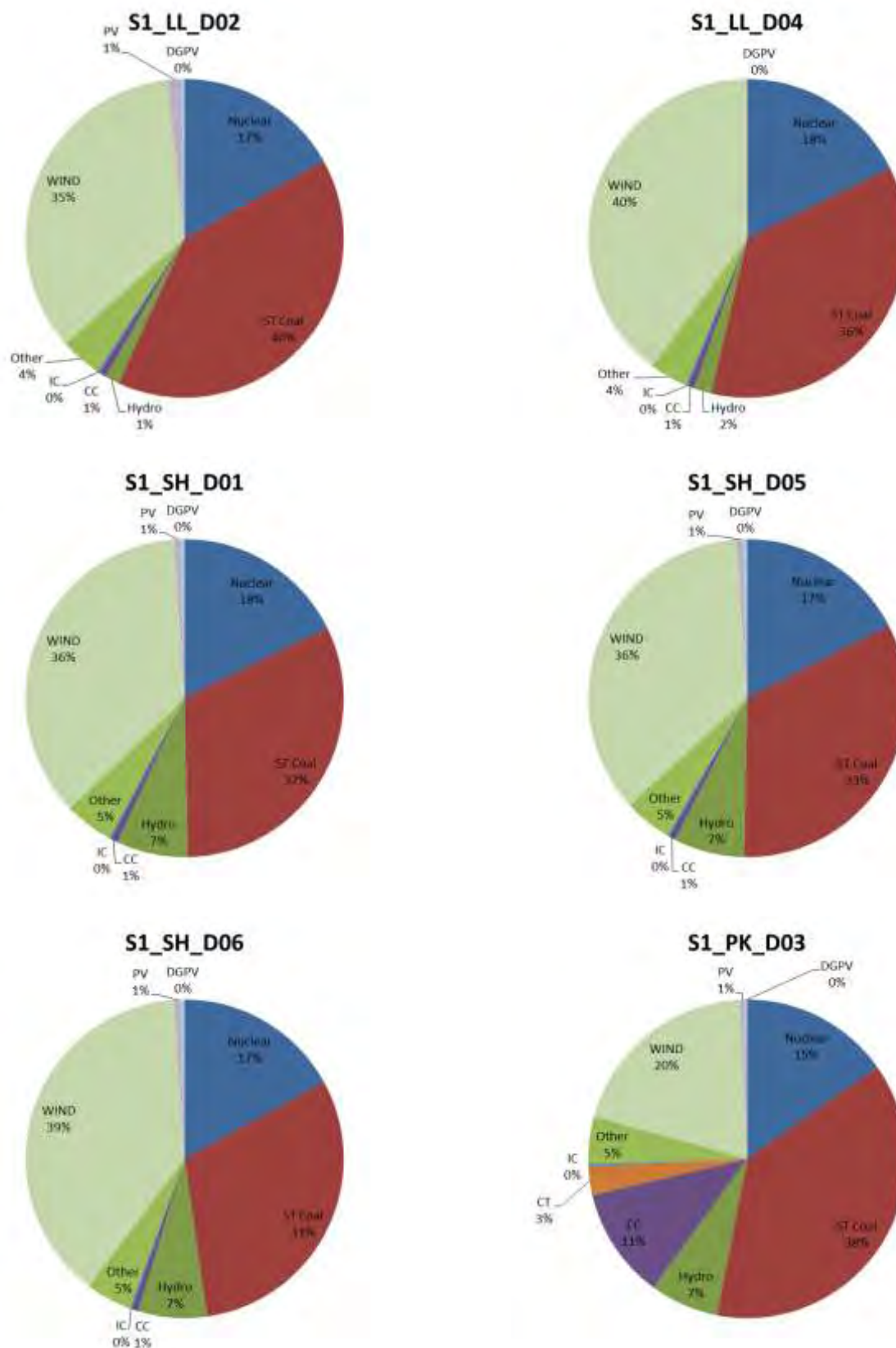


Figure 8-2 Minnesota Centric Percentage Generation Dispatch by Type

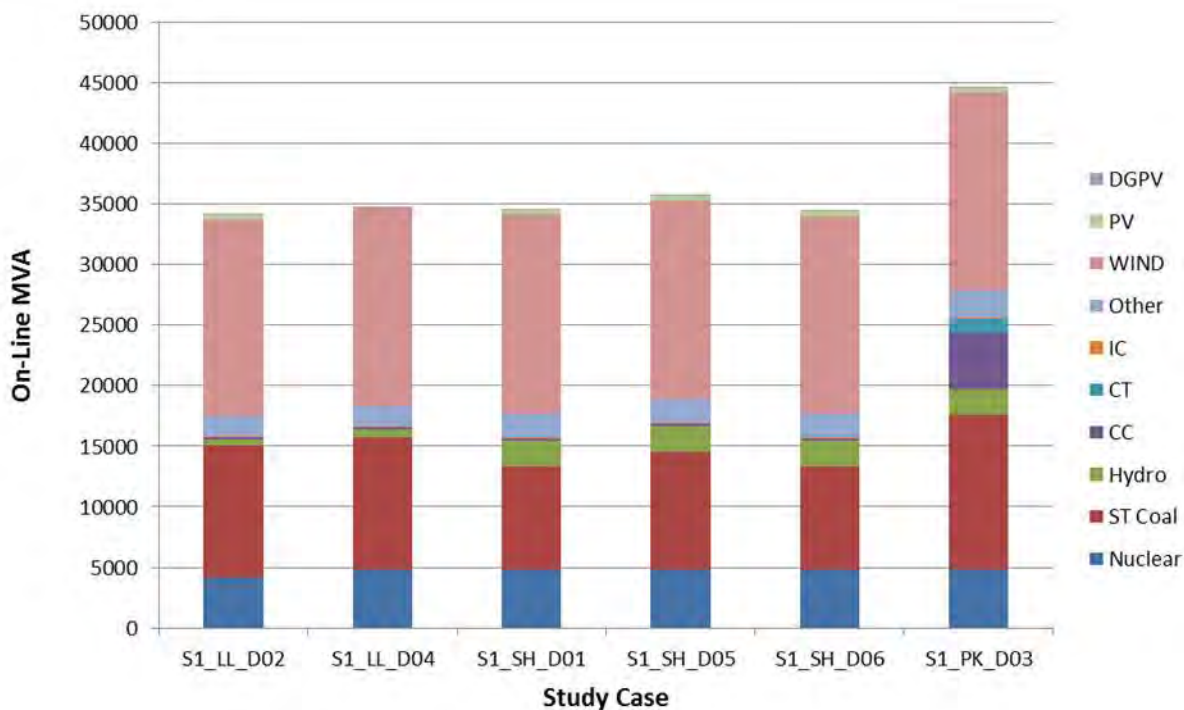


Figure 8-3 Minnesota Centric Commitment (MVA) by Unit Type

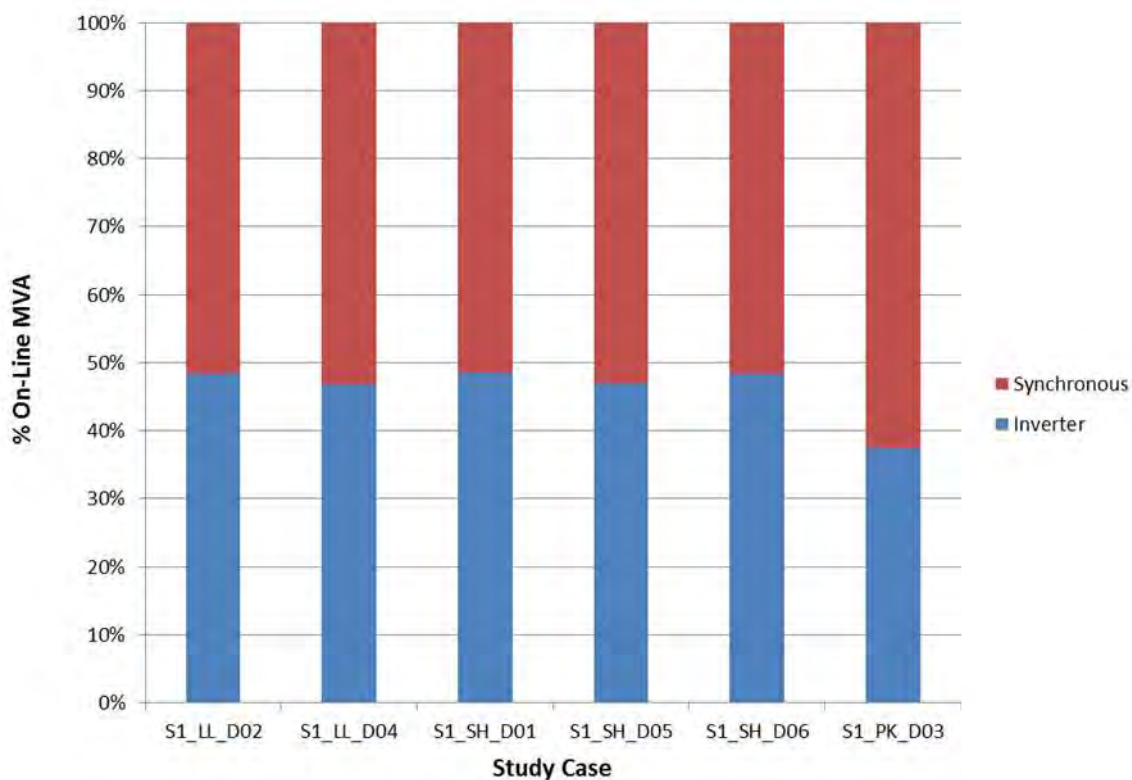


Figure 8-4 Percentage of On-line Non- vs Synchronous MVA

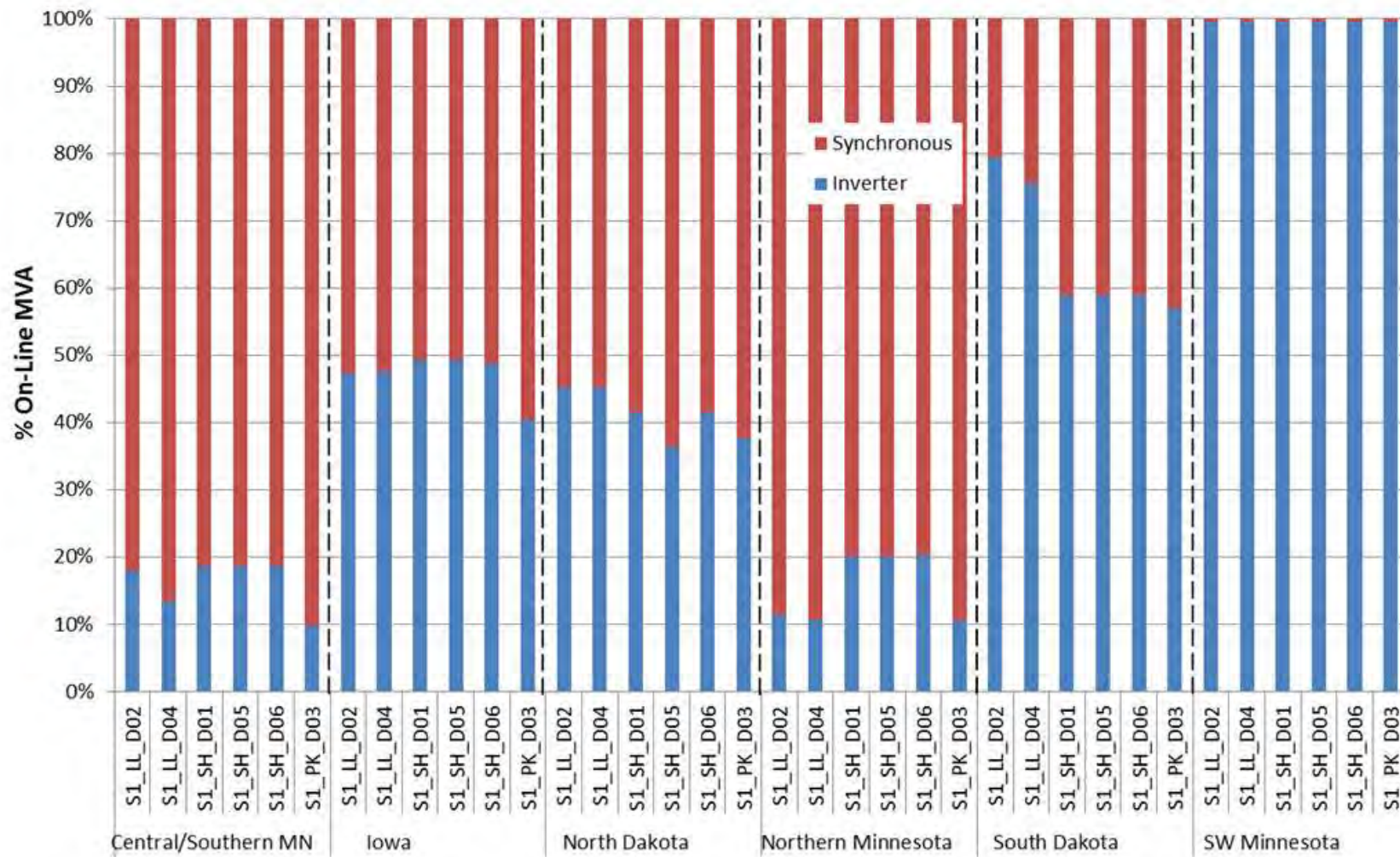


Figure 8-5 Percentage of online, non- and synchronous MVA by Sub-Region

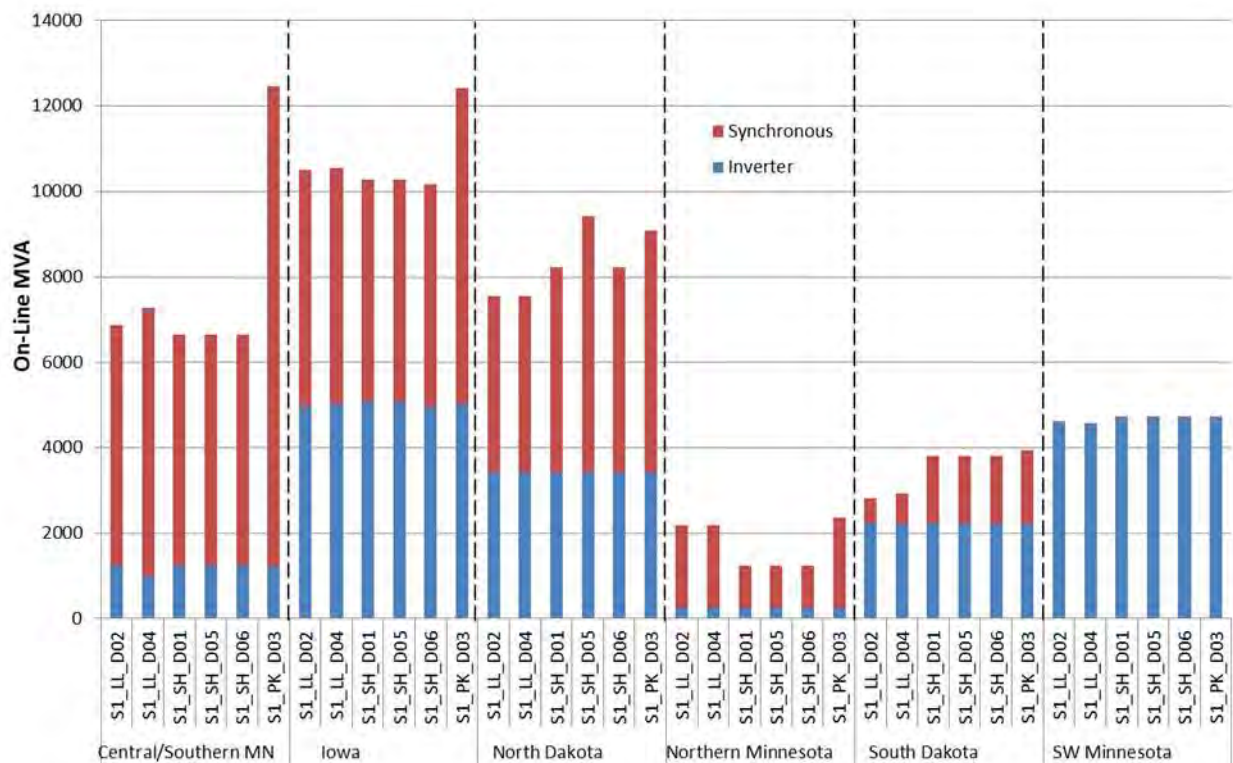


Figure 8-6 Online MVA of synchronous and non-synch Generation by Region

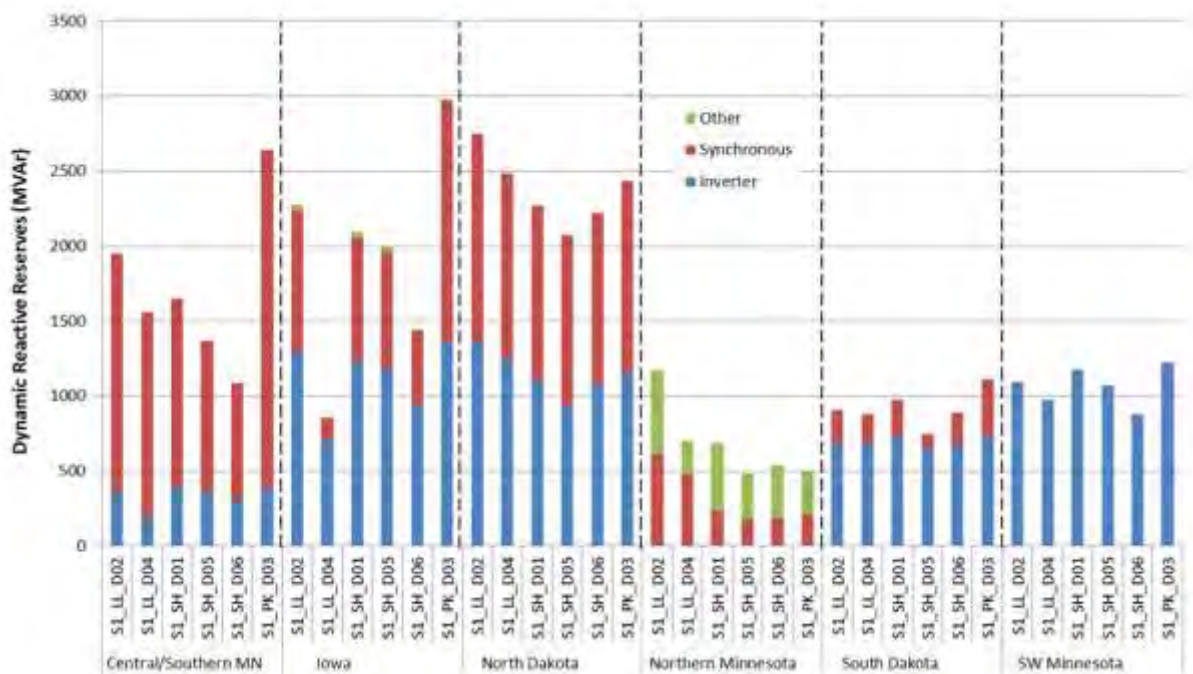


Figure 8-7 Dynamic Reactive Reserves of synchronous and non-synch Generation by Region

8.2 Voltage Regulation & Stability Analysis

8.2.1 Disturbances

This study considers a wide range of contingencies, listed in Table 8-2. The list of faults covers reference disturbances, disturbances in areas with low short circuit strength and faults along transmission interfaces. Faults 1 through 5 are established contingencies that test the traditional stability limitations of the system. Faults 6 through 10 (LSC1 through LSC5) and 16 were selected based on the weak system (low short circuit strength) analysis. These lines have the highest contribution to short circuit strength of the SW Minnesota region. Fault 11 tests the stability and voltage recovery of the Twin Cities area and Fault 12 tests a fault with generation tripping near SW Minnesota. Faults 13 through 16 were developed for high transmission loading cases (cases 5 through 7) only.

Table 8-2 Fault Description for Stability Analysis

No.	Fault Name	Description
1	EI2	CU HVDC Permanent Bipole fault with tripping of both Coal Creek units
2	AG1	SLG fault with breaker fail at Leland Olds on the Ft. Thompson 345 kV line
3	AG3	3 phase fault at Leland Olds on Ft. Thompson 345 kV line, Clear both ends of the line in 4 cycles
4	NAD	4cycles 3 phase fault on the Dorsey to Forbes 500 kV line D602F at Forbes. Runback bi-poles that terminate at Dorsey
5	PCS	SLG fault t with breaker fail at King with 8P6 stuck. Trips King-EauClaire-Arpin and King-Chisago 345 kV line
6	LSC1	3 Φ Fault at Nobles on Lakefield Jct 345 kV line, clear both ends of the line in 4 cycles
7	LSC2	3 Φ Fault at Fallow on Grimes 345 kV line, clear both ends of the line in 4 cycles
8	LSC3	3 Φ Fault at Brookings Co. on Big Stone South 345 kV line, clear both ends of the line in 4 cycles
9	LSC4	3 Φ Fault at Split Rock on White 345 kV line, clear both ends of the line in 4 cycles
10	LSC5	3 Φ Fault at Split Rock on Sioux City 345 kV line, clear both ends of the line in 4 cycles
11	Trip_DEERCK	3 Φ Fault at Deer Creek 345 kV bus, clear fault in 4 cycles followed by tripping Deer Creek CC generator
12	Term_King	3 Φ Fault at KOLMNLK3 on Terminal 345 kV line, clear both ends of the line in 4 cycles
13	AG1_v2	Single-line-to-ground fault with breaker fail at Leland Olds on the Groton 3 345 kV line
14	AG3_v2	Three-phase fault at Leland Olds on the Groton 3 345 kV line. Clear both ends of the line in 4 cycles
15	briggs	Three-phase fault at Briggs on the NMA 345 kV line. Clear both ends of the line in 4 cycles
16	sheas	Three-phase fault at SHEAS LK3 on the HELENA 3 345 kV line. Clear both ends of the line in 4 cycles

8.2.2 Overall Results

Transient stability analysis evaluated system response to all fault listed in Table 8-2 . Faults 1 through 12 were tested on all cases while faults 13 through 16 were tested on high transmission loading cases (cases 5 through 7) only.

All stability simulations were evaluated using the criteria describe in Section 5. This includes first swing and angular stability, possible system separation and cascading outage conditions based on operation of the system-wide generic impedance relay and post-fault voltage recovery. Transient response was considered stable if all units maintain stable response, voltage recovery meets testing criteria and there were no inadvertent impedance relay operations. The results of transient stability analysis are summarized in the Table 8-3. All tested scenarios produce transiently stable response with acceptable voltage recovery.

Table 8-3 Transient Stability Analysis Results

No	Fault Name	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
1	EI2	stable	stable	stable	stable	stable	stable	stable
2	AG1	stable	stable	stable	stable	stable	stable	stable
3	AG3	stable	stable	stable	stable	stable	stable	stable
4	NAD	stable	stable	stable	stable	stable	stable	stable
5	PCS	stable	stable	stable	stable	stable	stable	stable
6	LSC1	stable	stable	stable	stable	stable	stable	stable
7	LSC2	stable	stable	stable	stable	stable	stable	stable
8	LSC3	stable	stable	stable	stable	stable	stable	stable
9	LSC4	stable	stable	stable	stable	stable	stable	stable
10	LSC5	stable	stable	stable	stable	stable	stable	stable
11	Trip_DEERCK	stable	stable	stable	stable	stable	stable	stable
12	Term_King	stable	stable	stable	stable	stable	stable	stable
13	AG1_v2	NT	NT	NT	NT	stable	NT	NT
14	AG3_v2	NT	NT	NT	NT	stable	NT	NT
15	briggs	NT	NT	NT	NT	NT	NT	stable
16	sheas	NT	NT	NT	NT	NT	stable	NT

* NT is "Not Tested"

For transient stability analysis in this study new monitoring signals are introduced. These signals include dynamic monitoring of total active and reactive output of different types of generation (i.e. synchronous, wind, PV) and load for each of Minnesota footprint regions. The plots of selected traces of transient stability simulations are presented in the sections below.

Transient stability cases are grouped into three categories based on criteria used for their development. The categories are:

1. High percentage non-synchronous condition;
2. High percentage of renewable conditions
3. High transfer conditions,

In the following section, the system response to selected faults is presented for each category of dispatch conditions.

8.2.3 High % NS conditions

The cases developed for high percentage of non-synchronous generation in Minnesota footprint are case 1, case 2 and case 3. The faults selected to represent system response on these cases are:

- Case 1:** Terminal King fault (3 Φ Fault at KOLMNLK3 on Terminal 345 kV line, clear both ends of the line in 4 cycles)
- Case 2:** Trip DEERCK fault (3 Φ Fault at Deer Creek 345 kV bus, clear fault in 4 cycles followed by tripping Deer Creek CC generator)
- Case 3:** AG3 fault (3 phase fault at Leland Olds on Ft. Thompson 345 kV line, Clear both ends of the line in 4 cycles)

This section lists plots of total Minnesota footprint as well as Minnesota-centric regions system generation and load response. The plots of system generation include active (left column) and reactive (right column) power of all synchronous generation, wind generation, PV plus DGPV and load. The plots show the total generation/load for the Minnesota-centric region and the six sub-regions. Also post fault voltage recovery of bus voltages close to a fault are presented.

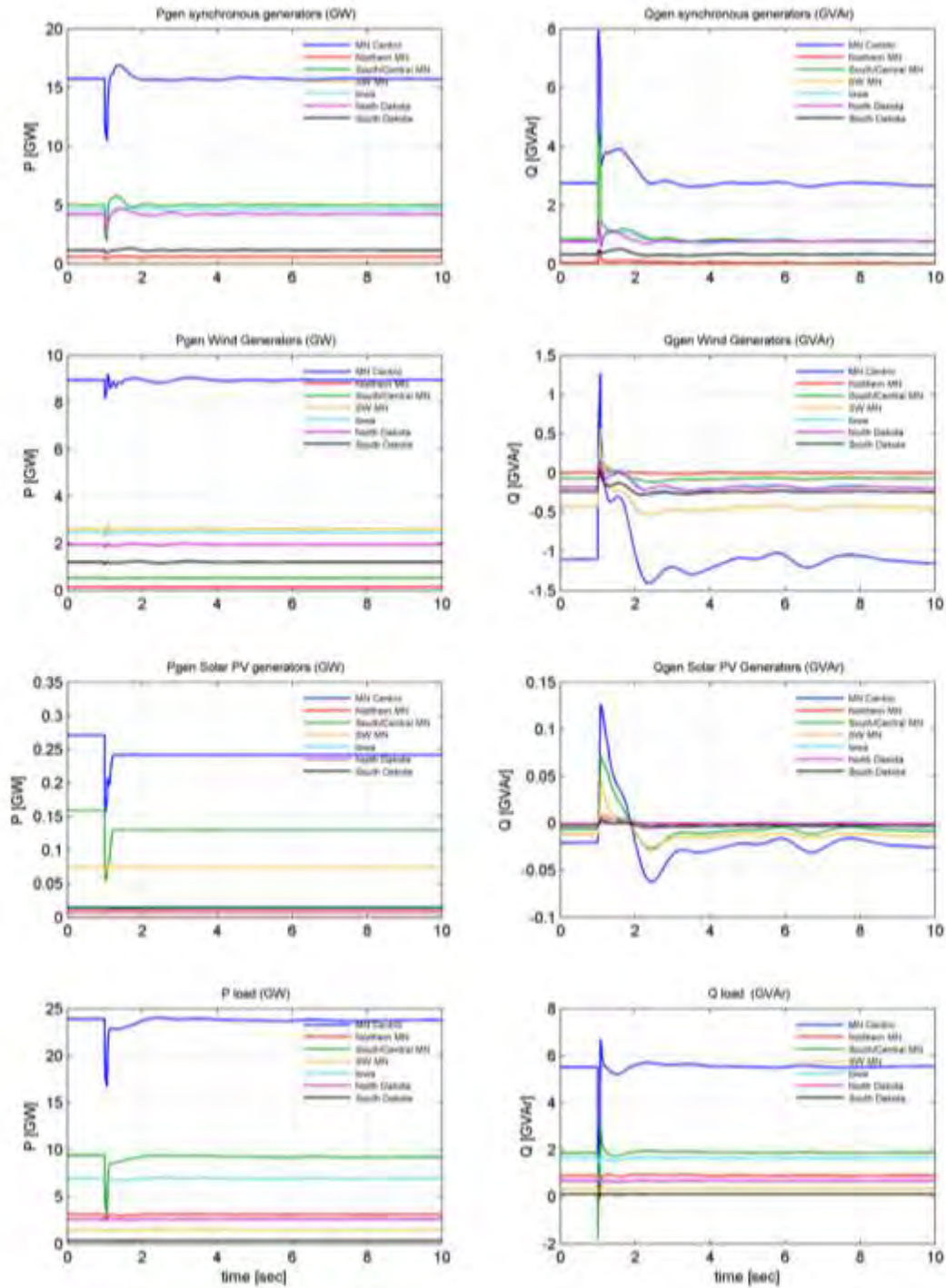


Figure 8-8 Case 1: Terminal King Fault Active and Reactive Response

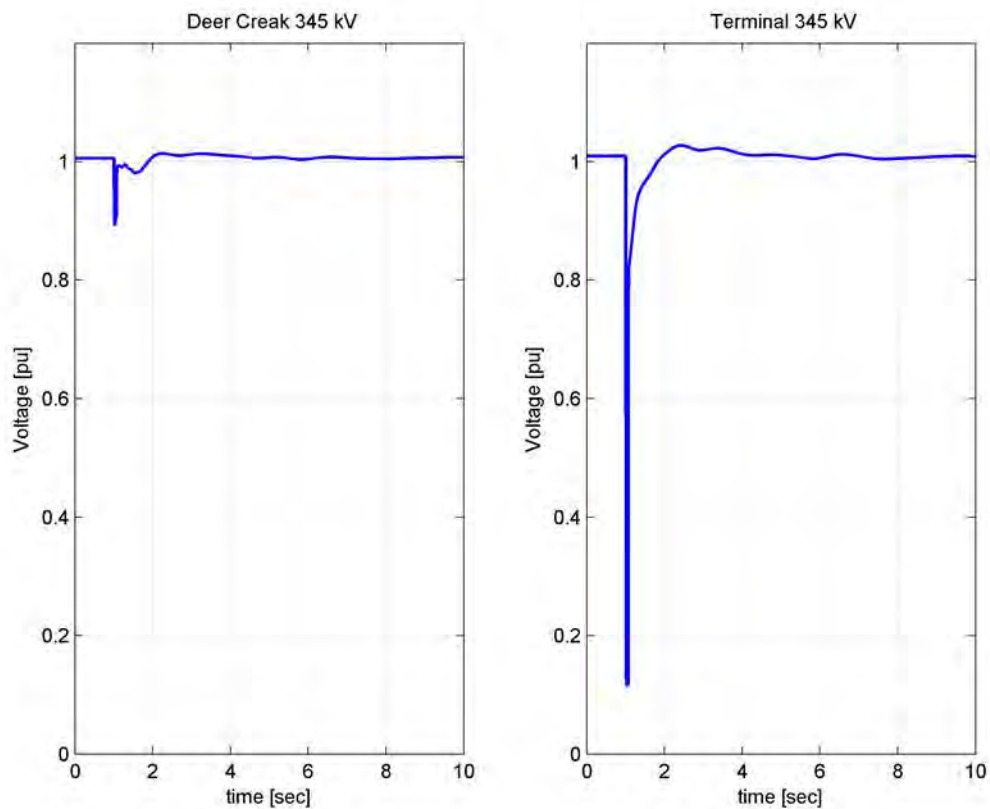


Figure 8-9 Case 1: Terminal King fault Voltage Magnitude

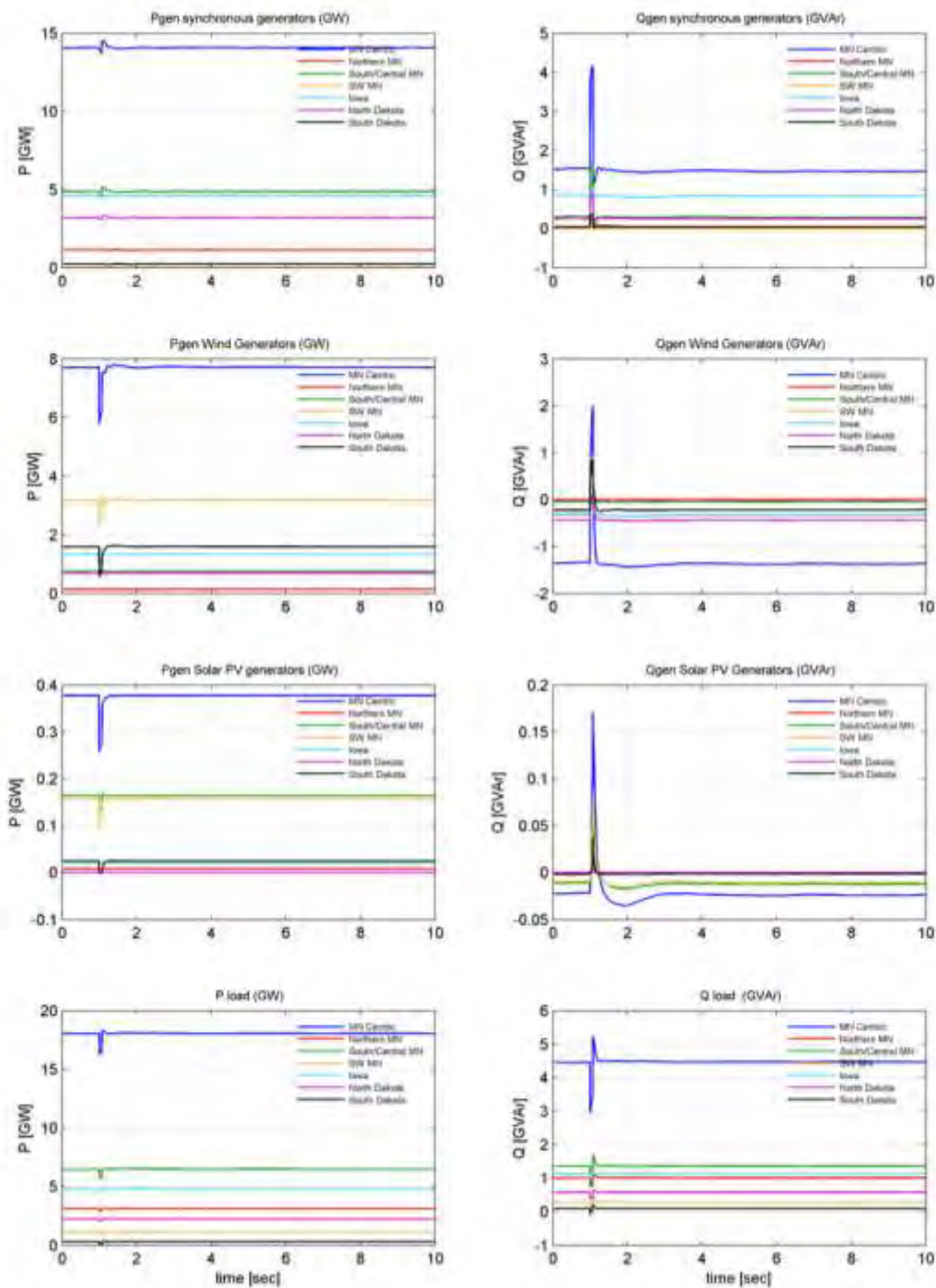


Figure 8-10 Case 2: Trip DEERCK fault Active and Reactive Response

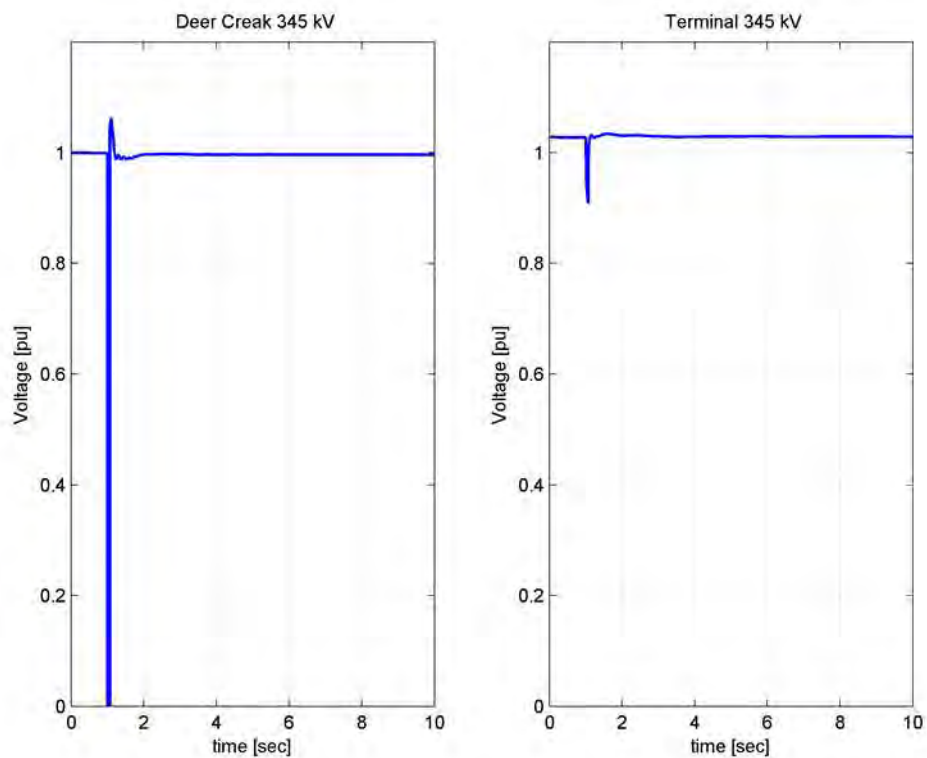


Figure 8-11 Case 2: Trip DEERCK fault Voltage Magnitude

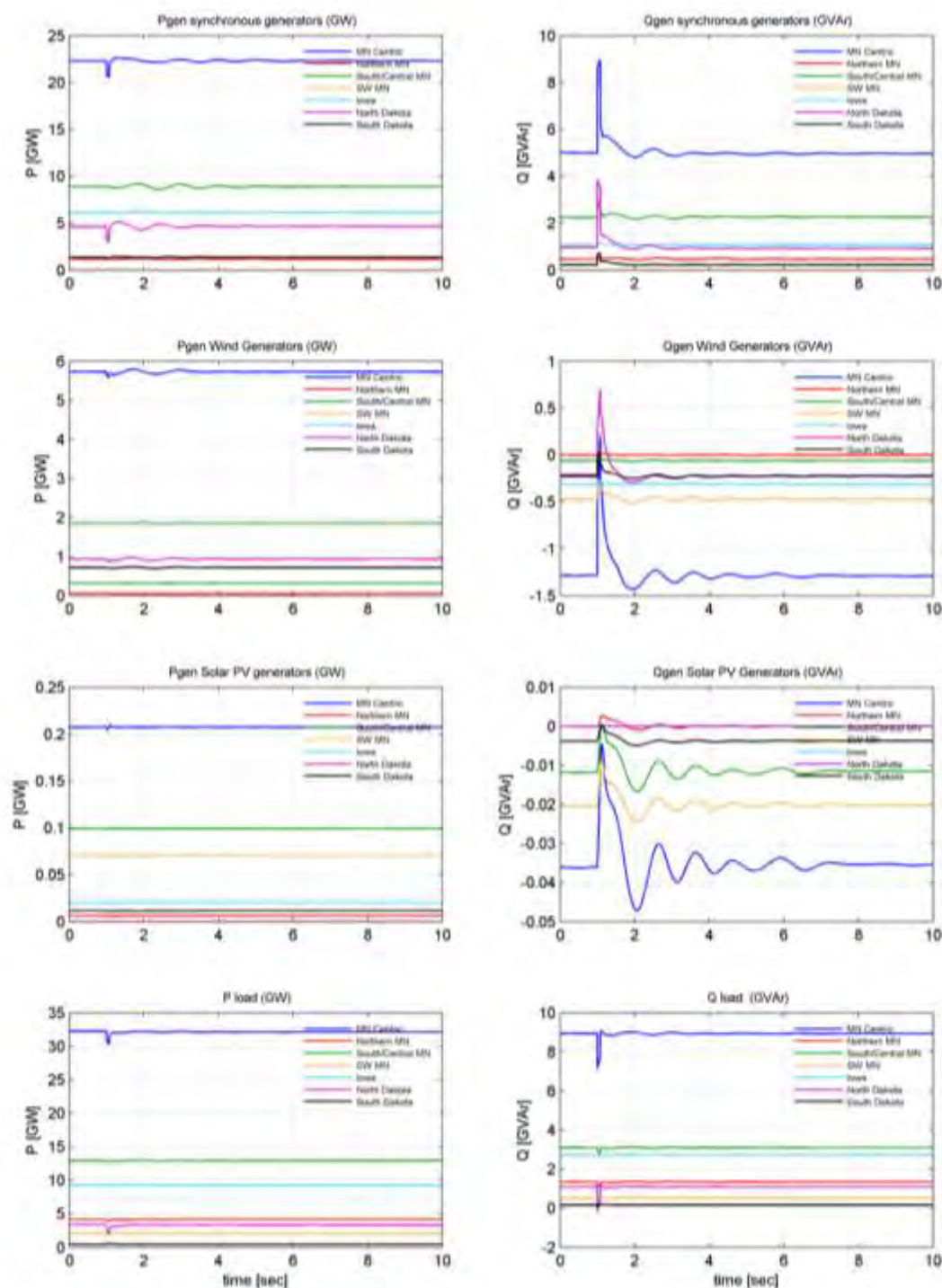


Figure 8-12 Case 3: AG3 fault Active and Reactive Response

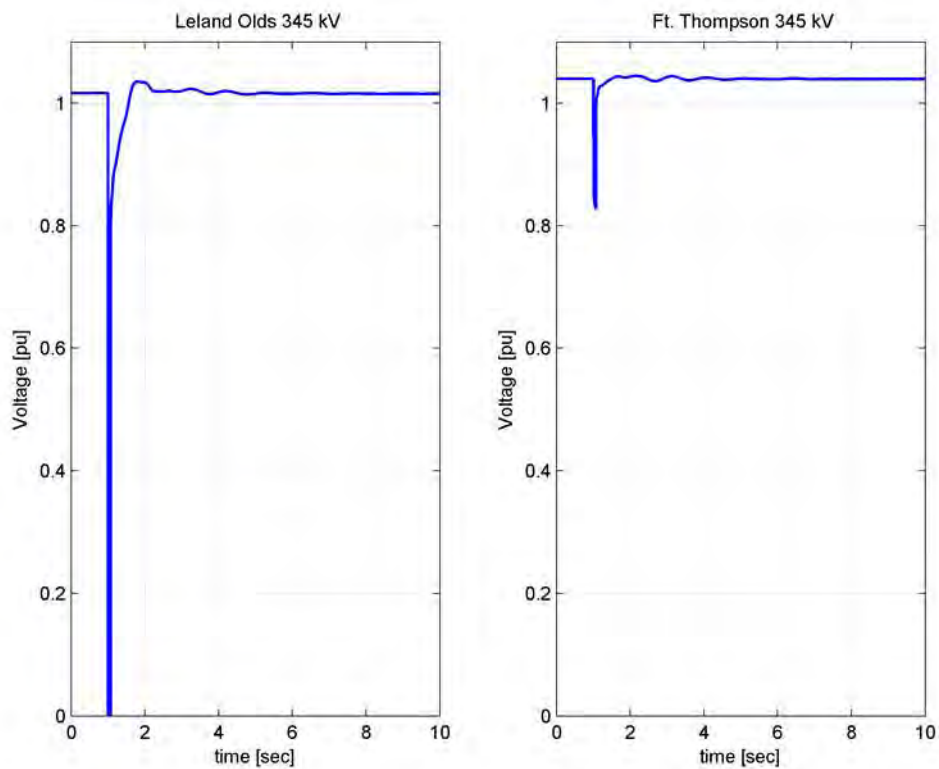


Figure 8-13 Case 3: AG3 fault Voltage Magnitude

8.2.4 High %RE conditions

The case developed to reflect high percentage of renewable penetration in Minnesota footprint is case 4. This is a light load case representing dispatch in early October during night hours between 12am and 7am. The fault selected is NAD fault (4cycles 3 phase fault on the Dorsey to Forbes 500 kV line D602F at Forbes. Runback bi-poles that terminate at Dorsey). Minnesota footprint generation and load response to a NAD fault is presented in Figure 8-14. Voltage recovery at 500 kV buses

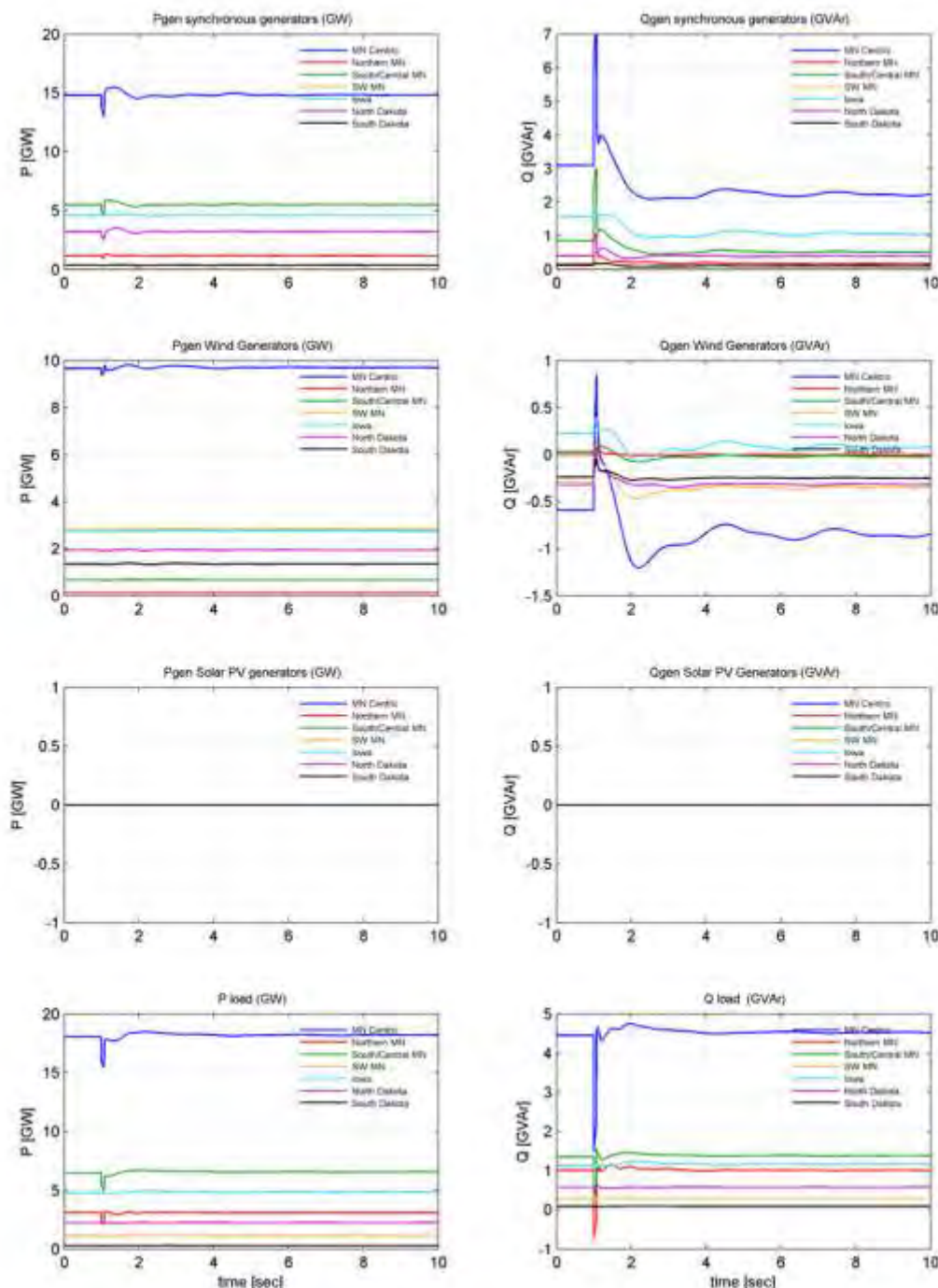


Figure 8-14 Case 4: NAD fault Active and Reactive Response

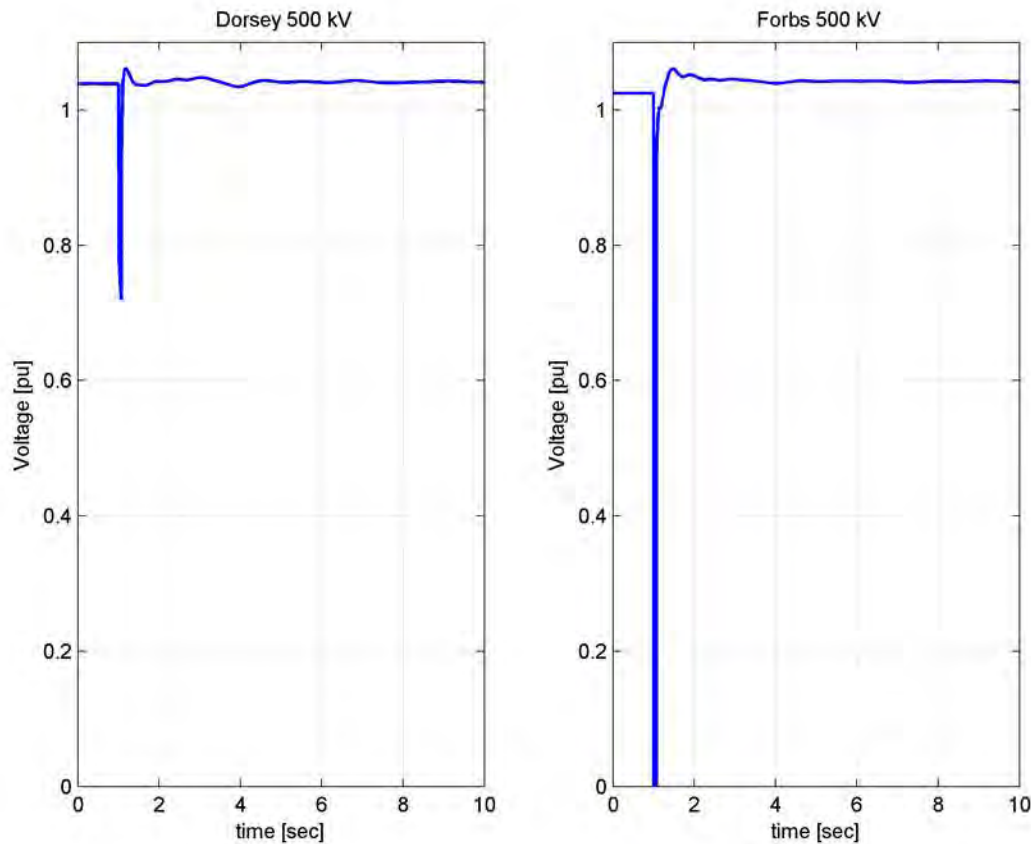


Figure 8-15 Case 4: NAD fault Voltage Magnitude

8.2.5 High Transfer Conditions

The case developed to reflect high transmission loading on NDEX, Buffalo Ridge Outlet and MWEX interfaces are case 5, case 6 and case 7 respectively. The faults selected to represent system response on these cases are:

1. Case 5: AG1_v2 (Single-line-to-ground fault with breaker fail at Leland Olds on the Groton 3 345 kV line)
2. Case 6: SHEAS (Three-phase fault at SHEAS LK3 on the HELENA 3 345 kV line. Clear both ends of the line in 4 cycles)
3. Case 7: BRIGS (Three-phase fault at Briggs on the NMA 345 kV line. Clear both ends of the line in 4 cycles)

Plots of Minnesota footprint area generation and load response as well as post fault voltage recovery is presented in Figure 8-16 through Figure 8-21.

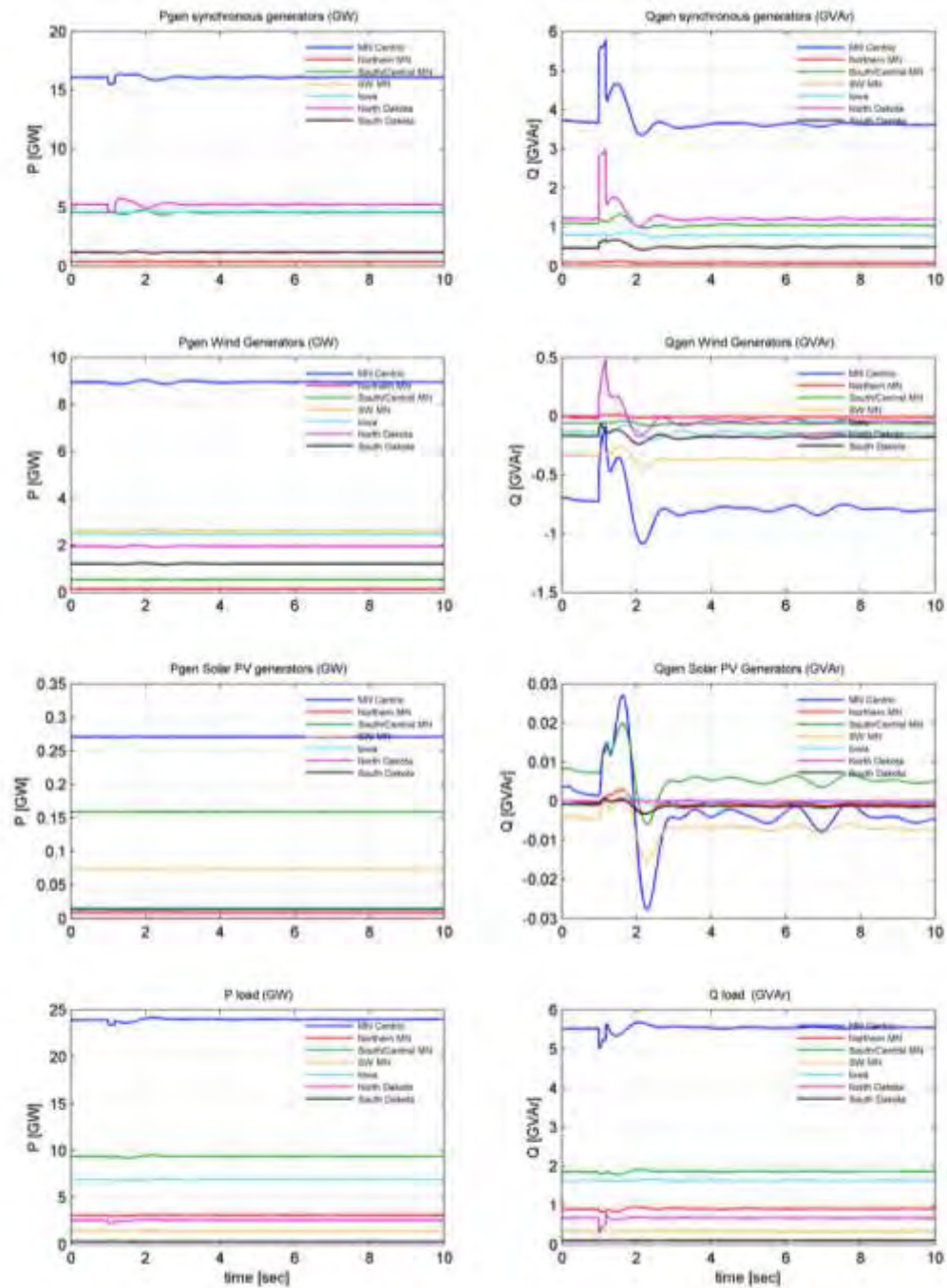


Figure 8-16 Case 5: AG1_v2 fault Active and Reactive Response

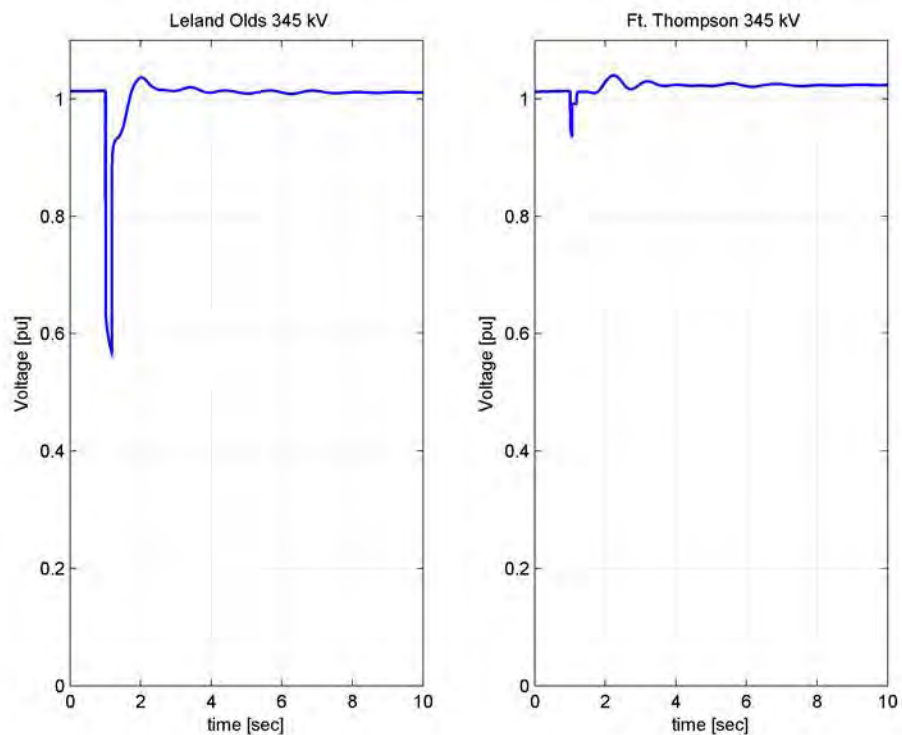


Figure 8-17 Case 5: AG1_v2 fault Voltage Magnitude

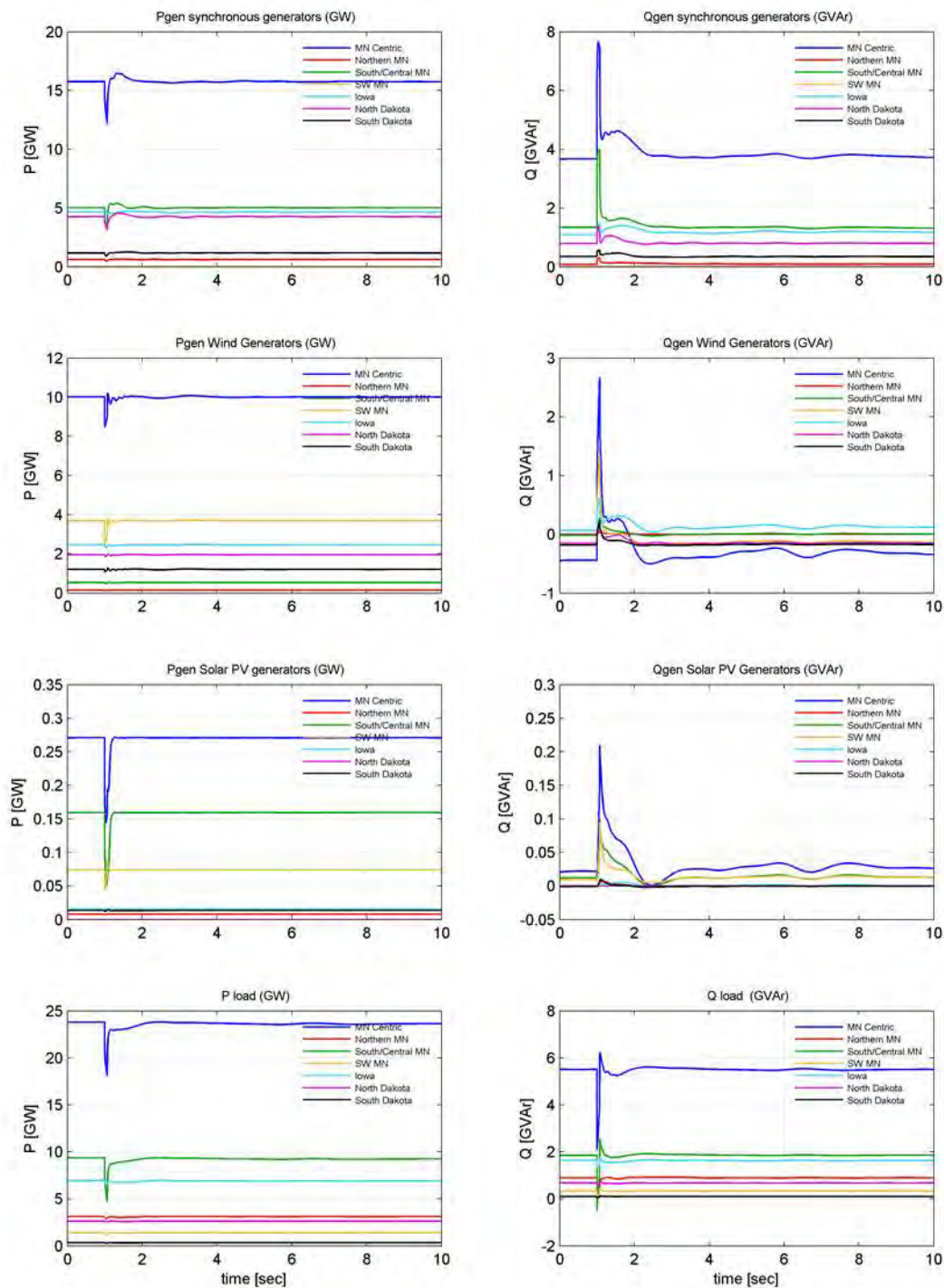


Figure 8-18 Case 6: SHEAS fault Active and Reactive Response

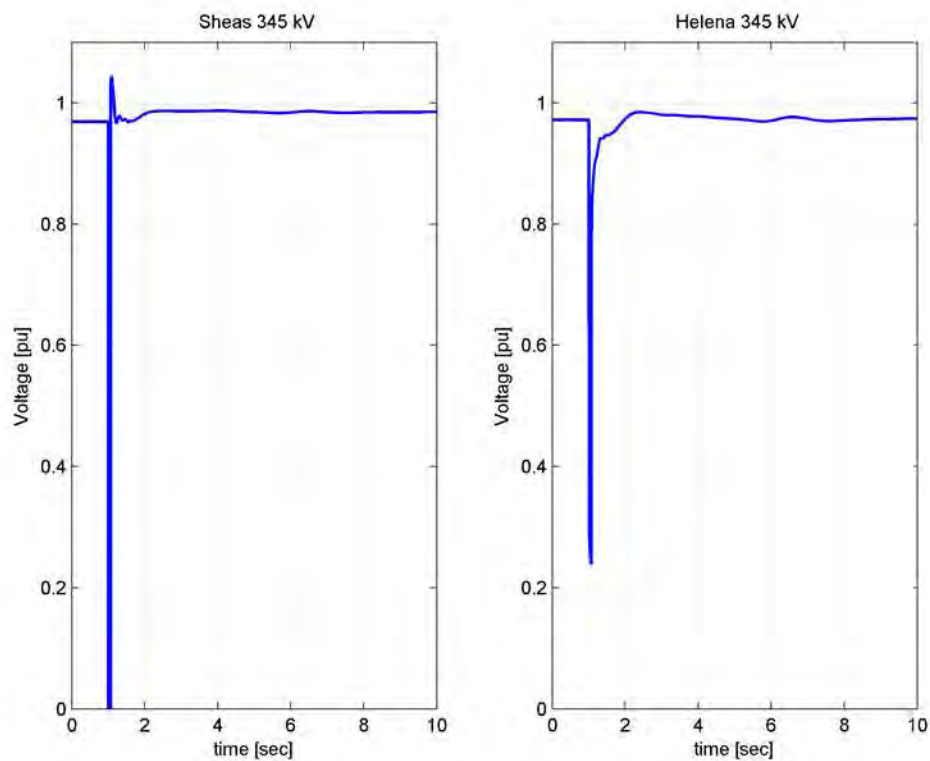


Figure 8-19 Case 6: SHEAS fault Voltage Magnitude

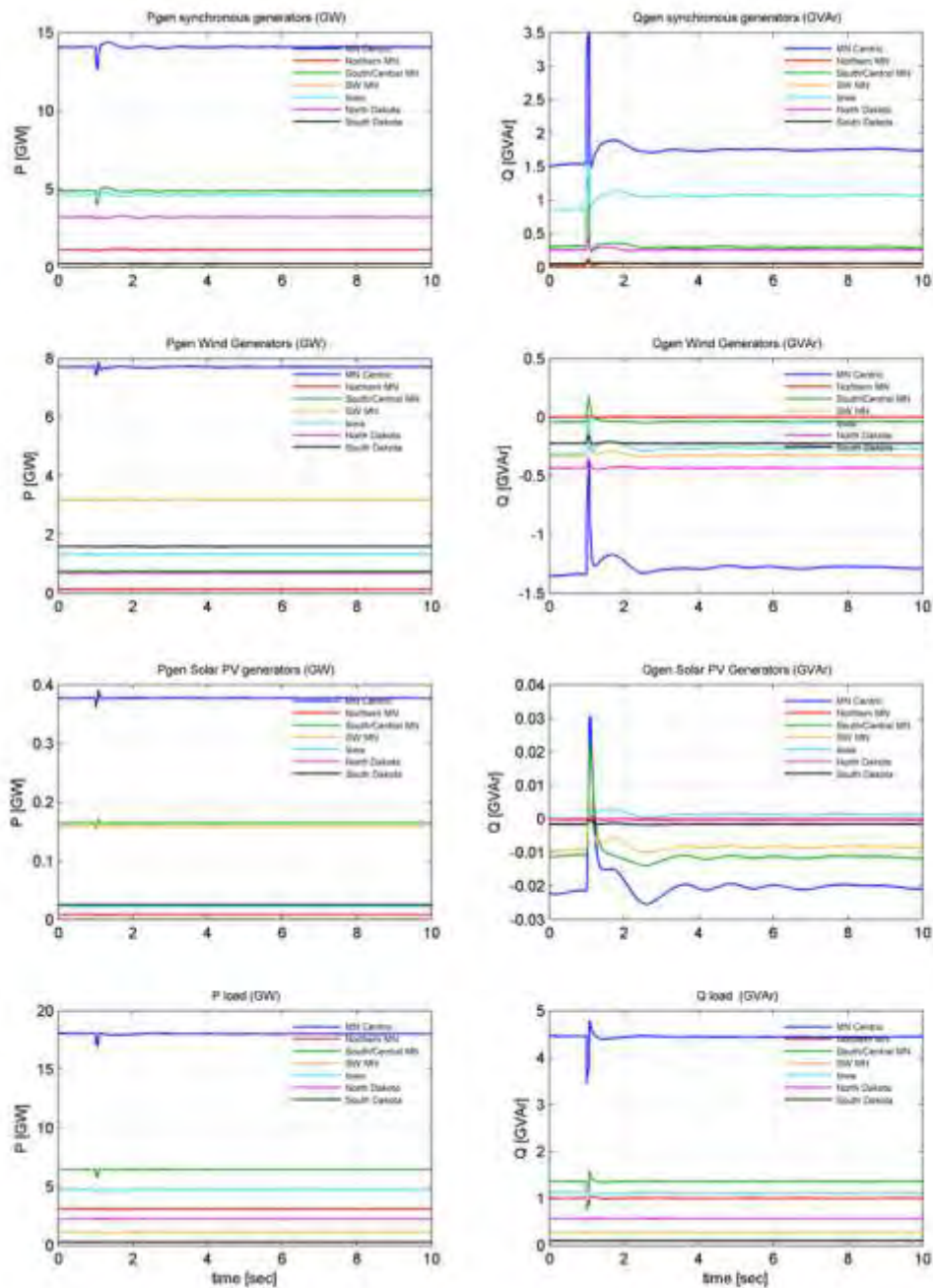


Figure 8-20 Case 7: BRIGGS fault Active and Reactive Response

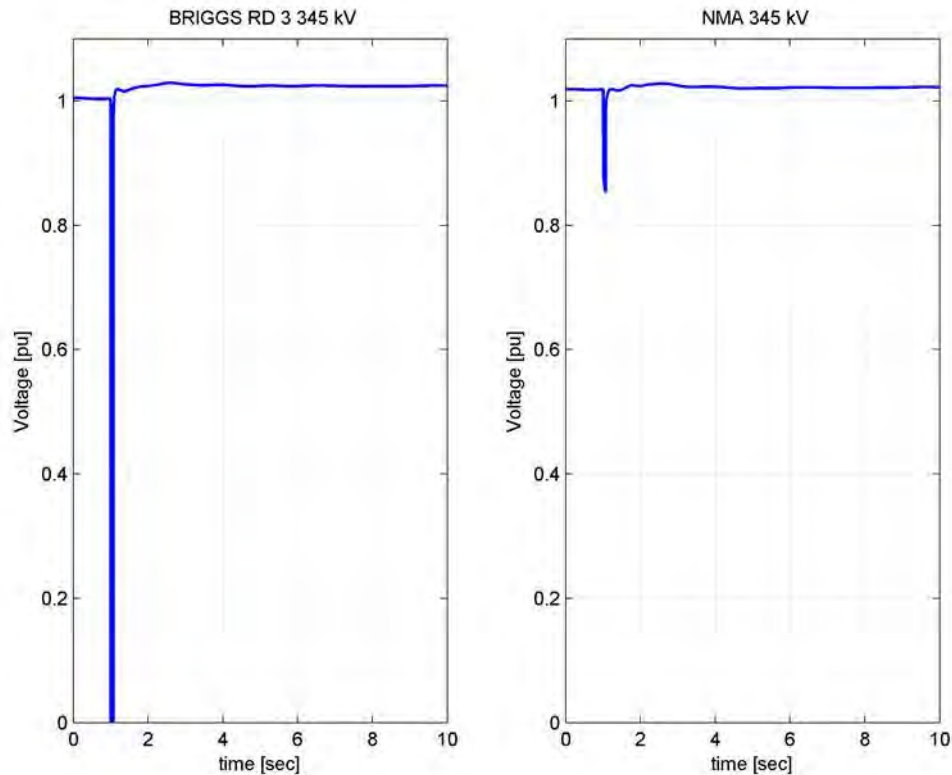


Figure 8-21 Case 7: BRIGGS fault Voltage Magnitude

8.3 Reactive Reserves

The dynamic reactive reserves for all test cases (plotted in Figure 8-7) were sufficient to maintain system stability and allow for acceptable voltage recovery. Both the transient voltage dip and post-transient voltages recovered met all screening criteria.

Sensitivity analysis was performed on two areas to test the response with lower dynamic reactive reserves. The first sensitivity was performed on a localized load pocket. When developing the power flow cases, low voltage and power flow convergence issues were observed in the Tac Harbor / Silver Bay area of Northern Minnesota. This area has a significant amount of industrial load, including over 75 MW of large synchronous motor load. Some of the production simulation hours had all Silver Bay and Tac Harbor units turned off. In most cases, the power flow failed to converge with these units turned off. If the power flow did solve with the generators off, voltages were well below 1.0 pu.

With all local generation off line, the Tac Harbor synchronous motors will be dynamically unstable for faults in the area. Turning on some units, either as generators or synchronous condensers will stabilize the motors. Though not tested, it is likely that new transmission and/or a static var compensator (SVC) would also stabilize the motors.

The second sensitivity was performed on the Manitoba Hydro (MH) HVDC ties and the 500 kV lines from MH to Minnesota. The 2028 power flow cases modeled a new HVDC tie into the Riel station along with reinforcements to the existing 500 kV system near the Iron Range. These reinforcements are intended to support higher MH exports. The HVDC inverter stations at Dorsey and Riel have several synchronous condensers to provide short circuit strength and reactive support. The S1_SH_D01 case has 2975 MW of MH exports. As noted above, all test disturbances are stable with acceptable post-fault voltage recovery for all of the test cases.

Several sensitivity simulations were performed on the shoulder load case (S1_SH_D01) with the Riel condensers turned off and the Dorsey condensers modeled with fixed field voltage. Modeling the Dorsey condensers with fixed field voltages allowed them to provide short circuit strength but not regulate voltages. Under these sensitivity test conditions, faults in Central Minnesota on the Terminal-King line caused a wide-spread instability. In order to stabilize this case, the MH exports had to be reduced by more than 500 MW.

This sensitivity analysis showed that localized dynamic reactive power support is critical to maintaining system stability. The current plans, as modeled in this study, address this issue and are sufficient for the anticipated levels of MH exports. The current practice of operating the Silver Bay and/or Tac Harbor generators to support the local industrial load provides strong local area voltage.

8.4 Weak Grid Analysis

As wind penetration increases and market commitment of synchronous resources decreases, there is a point where the grid is no longer strong enough (i.e. the impedance is too high) to support stable operation of the power electronic converters within the wind generators and PV plants. This can happen for single machines as well as for groups of machines in a wind plant and groups of wind plants in a region.

This is an emerging issue. Very few systems have faced this issue in actual operation (e.g. a few events in Texas before the transmission system was reinforced). Very few transmission engineers understand this issue in depth, as it has its roots within the lowest-level internal controllers of the wind and solar power electronic converter equipment. Knowledge of this issue is built upon converter performance tests and detailed analysis using transient simulation tools such as Power Systems Computer Aided Design (PSCAD) and ElectroMagnetic Transients Program (EMTP). Since such tools and analytical methods are not well suited to studying large-scale risks for many plants over wide geographic areas, the challenge is to take what is learned from detailed analysis of a few plants and extend that learning across larger regions using more practical methods.

8.4.1 Composite Short Circuit Ratio Concepts

Short Circuit Ratio (SCR) is a method used to screen for weak grid conditions near power electronic converters. This method has been used for decades to screen for weak grid conditions near HVDC converters and is currently being applied to wind plants. SCR is the ratio of the available system strength (measured in short circuit MVA) to the MW rating of the wind or PV plant.

While SCR is well established and trusted for HVDC and single-plant wind projects, it is not well suited for areas with multiple wind and solar plants in close proximity. For such cases, the industry is moving towards the Composite Short Circuit Ratio (CSCR) of all plants together.

Like SCR, this is the ratio of available short circuit MVA to plant MW rating. However, it accounts for multiple nearby plants by taking the ratio of composite short circuit MVA to that total MW rating of all plants.

The composite short circuit MVA is calculated by tying together the buses at the low side of the interconnection transformers of all wind and/or PV plants, creating a “composite” bus. The short circuit MVA is then calculated at the composite bus through normal fault calculation methods. CSCR is the ratio of the composite short circuit MVA to the total MW rating of all the wind and PV plants. This is shown in Figure 8-22. The wind and PV plants are assumed to have no fault current contribution when calculating CSCR.

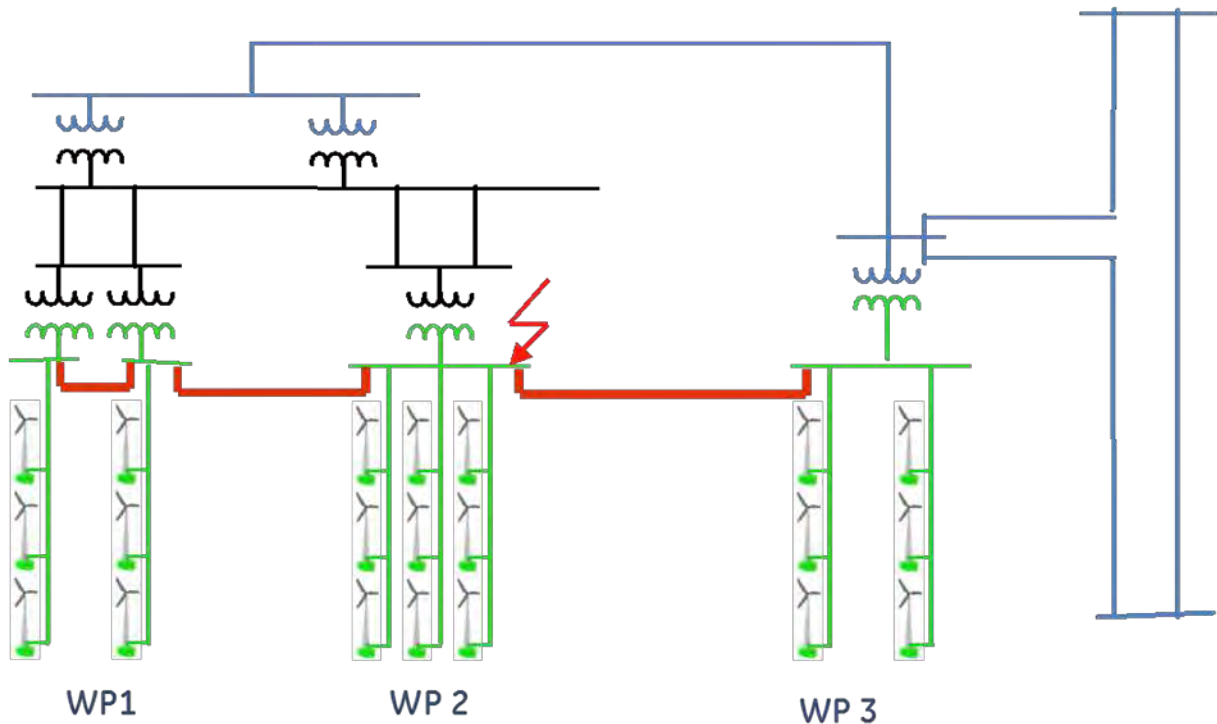


Figure 8-22 Example of composite, short-circuit MVA at Multiple Wind Plants

CSCR is calculated for normal and contingency conditions and considers generation off line. Unlike normal fault calculations, where the object is to determine the strongest system condition and highest fault current, CSCR calculations are intended to determine the weakest conditions the wind and PV will be expected to operate under.

Based on current wind turbine generator technology, a system with a CSCR above about 2.5 to 3 is considered strong. The wind plants should not have control instability issues. CSCR below about 1.7 to 1.5 is considered weak. CSCR below 1.0 would likely require mitigation, either at the plant through control tuning, by strengthening the system (e.g. new transmission or synchronous machines) or a combination of both. There is less experience with an acceptable CSCR level for PV plants.

8.4.2 Identifying Weak Regions

One of the challenges in evaluating weak grid issues for this study was identifying regions of the Minnesota system and the groups of wind and PV plants within those regions that could have low CSCR. The approach used for this analysis was to find relatively weak regions where voltage regulation was impacted more by wind and PV than by synchronous generation.

A measure of voltage regulation ratio was developed as the ratio of Thevenin impedance looking into the terminals of all synchronous generation to the Thevenin impedance looking into the terminals of all wind and PV generation. The Thevenin impedance was calculated taking the MVA rating of each unit into account. A low Thevenin impedance indicates a bus with strong voltage regulation and a high impedance indicates less voltage regulation. Since the voltage regulation ratio was defined as synchronous to non-synchronous Thevenin impedance, a ratio greater than 1.0 points to a bus with higher control from wind and PV than from synchronous generation. This corresponds to the regional measure of %NS, but on a substation level.

The voltage regulation ratio was calculated at all 230 kV and above Minnesota-centric buses. The total short circuit MVA was also calculated at the same buses. These two measures were then plotted for all buses and used to identify possible weak system areas with high renewables. This is shown in Figure 8-23. Each point in the plot represents a transmission bus, color coded by the six Minnesota-centric sub-regions. This plot is for n-0 transmission condition for the shoulder load case 1 dispatch (S1_SH_D01), as this case had the overall highest percent non-synchronous generation.

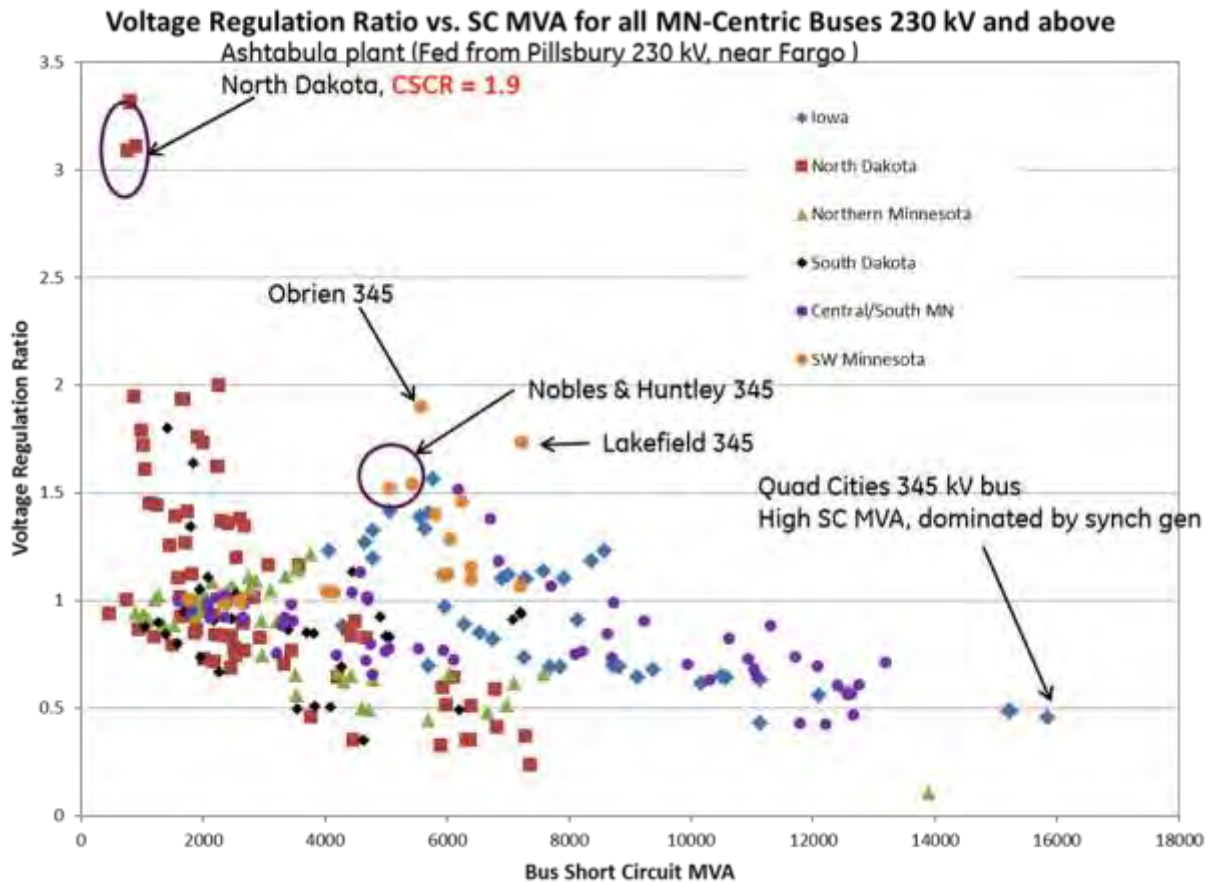
Three clusters of buses are highlighted on the plot. Quad Cities 345 kV bus has 16,000 MVA of short circuit strength and a voltage regulation ratio less than 0.5. This is to be expected, since both Quad Cities nuclear generating units are in service and dominate the voltage regulation at the transmission bus.

The Ashtabula plant in North Dakota is fed from Pillsbury 230 kV, near Fargo. This group of 230 kV buses, highlighted in the upper left corner of the plot, has a voltage regulation ratio above 3.0 and 710 MVA of short circuit strength. This is clearly a system dominated by wind generation with little short circuit strength. The three Ashtabula wind sites have a total capacity of 377 MW. This gives a CSCR of 1.88 under n-0 transmission conditions (710 MVA/377 MW). This is in the range of concern, particularly since the CSCR would likely be lower with transmission outages.

The transmission buses in SW Minnesota are shown with orange circles. Four 345 kV buses are highlighted; O'Brien, Nobles, Huntley and Lakefield. These buses have a relatively high short circuit strength (5000 to 7000 MVA), but also have a high voltage regulation ratio (1.5 to 2.0). These buses are in the Buffalo Ridge area. The high voltage regulation ratio is due to the large amount of renewables in SW Minnesota (4344 MW total for S1). The short circuit strength is due to the strong 345 kV transmission around the area, connecting it to synchronous generation to the west, south and east. System strength and CSCR calculations in this region are presented in the next section.

The analysis was also used to identify additional contingencies for the stability analysis. Critical transmission lines were identified based on initial loading (i.e. power flow in the base condition) and on the fault current contribution for faults on 345 kV buses around the Buffalo Ridge area. Tripping transmission lines that provide the highest fault current and have the highest initial loading will be

most challenging from a weak-system and a transient disruption standpoint. Outages identified from the weak system analysis are identified as LSC1 through LSC5, and SHEAS in Table 8-2.



**Figure 8-23 SC MVA vs. Voltage Regulation Ratio
for Minnesota-Centric Transmission Buses**

8.4.3 Southwestern Minnesota CSCR

As discussed above, the SW Minnesota region has a high concentration of renewable generation and relatively high short circuit strength under normal operating conditions. In total, the region has 4344 MW of renewable generation capacity for the S1 system. The rated MW of each plant in this area is listed in Table 8-4. New PV and New Wind represent renewable generation added for the baseline and S1 scenarios.

The CSCR for the composite of all of the SW Minnesota renewable generation was calculated by tying the low side of the interconnection transformers together with all renewable generation disconnected. For the S1_SH_D01 case, the CSCR is 9040 MVA over 4344 MW, or 2.08. This is in the caution region.

The CSCR was calculated with generation throughout the Minnesota-centric region decommitted. In general, no single generator had a significant impact on CSCR. The greatest reduction was seen for decommitting both Prairie Island units (two 659 MVA nuclear units northeast of Buffalo Ridge).

With both of these units off line, CSCR drops to from 2.08 to 2.00. Decommitting Neal 4 (711 MVA unit near Buffalo Ridge) reduced CSCR to 2.04.

Other decommitted units evaluated include Streeter, Ames, Coal Creek, Big Stone, Willmar, Heskett, JP Madgett, Stanton and King. These units were selected based on their commitment across all six stability cases and their operation in all of the selected hours. With all of these units off line, CSCR drops from 2.08 to 1.99. This is not a significant drop in CSCR, given the number of units decommitted. Sensitivity analysis was conducted where Hydro units at Garrison, Big Bend and Oahe were decommitted. These units had very little measurable impact on CSCR in the SW Minnesota region.

Transmission outages play a larger role in CSCR than individual generator status. Loss of the Sheas Lake to Helena 345 kV lines decreases the CSCR from 2.08 to 1.90. All other transmission outages tested has much less impact on CSCR. For example, loss of the Nobles-Lakefield or White-Split Rock 345 kV lines will only reduce the CSCR from 2.08 to 2.07. Several other transmission contingencies were studied but none had a significant impact on CSCR.

8.4.4 Mitigation through Wind/PV Inverter Controls

Standard inverter controls and setting procedures may not be sufficient for weak system applications. Loop gains of internal control functions inherently increase when system impedance increases, thereby reducing the stability margin of the controllers. Developers and equipment vendors must be made aware when new plants are being proposed for weak system regions so they can design/tune controls to address the issue. Wind plant vendors have made significant progress in designing wind and solar plant control systems that are compatible with weak system applications.

This approach becomes somewhat more difficult when there are wind/solar plants from multiple vendors in one region. The level of analysis requires detailed modeling of all affected wind plants at a level of detail that requires the use of proprietary control design information from the vendors. Vendors are very reluctant to share such data, except with independent consultants who can guarantee strict data security. However, this approach is gaining traction and a few projects have made effective implementations. The key to success is that project developers and equipment vendors must be informed beforehand that a given wind or solar plant will be installed at a weak system location. This enables the appropriate control design studies to be initiated before the project is installed.

In the event that such control-based approaches are not sufficient, it would be possible to further improve weak system performance by employing one or more of the system-level mitigations discussed below.

8.4.5 Low CSCR Mitigation

Committing additional generation will increase CSCR, but the increase is not drastic unless large blocks of units are put on line. For example, committing all coal units rated above 50 MVA in the MN centric footprint (7160 MVA total) increases the CSCR from 2.08 to 2.18. This is a very modest increase for such a large amount of committed generation. Therefore, mitigating low CSCR issues through commitment of existing generation is not a reasonable solution.

Two more reasonable methods available to increase CSCR in SW Minnesota are:

1. Add new synchronous machines, either generators or condensers, in the SW Minnesota region.
2. Lower the impedance between the region and the surrounding synchronous generation through new transmission, new 345/115 kV transformers or lower impedance transformers at the renewable generation sites.

Analysis considered the impact of adding synchronous condensers at several 345 kV and 115 kV buses in the Buffalo Ridge region.

Synchronous condensers are synchronous machines that have the same voltage control and dynamic reactive power capabilities as synchronous generators. Synchronous condensers are not connected to prime movers (e.g. steam turbines or combustion turbines), so they do not generate power.

Adding the condensers at the 115 kV level had the greatest increase in CSCR, since they were placed electrically closer to the renewable sites than on the higher voltage buses. For example, adding a 500 MVA of synchronous condensers at Lyon Co 115 kV and another 500 MVA at Nobles 115 kV increased the CSCR to 2.4. Moving the condensers to the 345 kV buses had a much lower improvement in CSCR.

Adding new transmission, particularly in the Sheas Lake area, will increase CSCR. Similarly, lower impedance transformers on the grid or in the renewable plants will increase CSCR. However, the benefits are likely to be modest.

Table 8-4 S1 Renewable Generation in SW Minnesota (Total MW Rating)

Sum of Pmax				
	S1_LL_D02	S1_LL_D04	S1_PK_D03	S1_SH_D01
PV	160		160	160
New PV	160		160	160
WIND	4076	4184	4184	4184
BRI3	290	290	290	290
BVIS		108	108	108
CHB3	281	281	281	281
CWS1	16	16	16	16
CWS2	14	14	14	14
DANJ	12	12	12	12
ELMC	151	151	151	151
ERID	10	10	10	10
G162	200	200	200	200
G164	200	200	200	200
G176	100	100	100	100
G255	100	100	100	100
G298	100	100	100	100
G358	35	35	35	35
G375	20	20	20	20
G426	150	150	150	150
G586	30	30	30	30
GRE-	227	227	227	227
JEFF	50	50	50	50
JHND	28	28	28	28
MMU	19	19	19	19
NOB_	200	200	200	200
ODIN	20	20	20	20
SRID	5	5	5	5
UILK	5	5	5	5
WEST	8	8	8	8
New Wind	1781	1781	1781	1781
WOLF	7	7	7	7
WOOD	10	10	10	10
WRID	7	7	7	7
Grand Total	4236	4184	4344	4344

9 KEY FINDINGS

This study examined two levels of increased wind and solar generation for Minnesota; 40% (represented by Scenarios 1 and 1a) and 50% (represented by Scenarios 2 and 2a). In the 40% Minnesota Scenario, MISO North/Central is at 15% (current state RESs). The 50% Minnesota Scenario also included an increase of 10% (to 25%) in the MISO North/Central region. Production simulation was used to examine annual hourly operation of the MISO North/Central system for all four of these scenarios. Transient and dynamic stability analysis was conducted for Scenarios 1 and 1a but not on Scenarios 2 and 2a.

9.1 General Conclusions for 40% RE Penetration in Minnesota

With wind and solar resources increased to achieve 40% renewable energy for Minnesota and 15% renewable energy for MISO North/Central, production simulation and transient/dynamic stability analysis results indicate that the system can be successfully operated for all hours of the year with no unserved load, no reserve violations, and minimal curtailment of renewable energy. This assumes sufficient transmission mitigations, as described in Chapter 4, to accommodate the additional wind and solar resources.

This is operationally achievable with most coal plants operated as baseload must-run units, similar to existing operating practice. It is also achievable if all coal plants are economically committed per MISO market signals, but additional analysis would be required to better understand implications, tradeoffs, and mitigations related to increased cycling duty.

Dynamic simulation results indicate that there are no fundamental system-wide dynamic stability or voltage regulation issues introduced by the renewable generation assumed in Scenario 1 and 1a. This assumes:

- New wind turbine generators are a mixture of Type 3 and Type 4 turbines with standard controls
- The new wind and utility-scale solar generation is compliant with present minimum performance requirements (i.e. they provide voltage regulation/reactive support and have zero-voltage ride through capability)
- Local-area issues are addressed through normal generator interconnection requirements

9.2 General Conclusions for 50% RE Penetration in Minnesota

With wind and solar resources increased to achieve 50% renewable energy in Minnesota and 25% renewable energy in MISO, production simulation results indicate that the system can be successfully operated for all hours of the year with no unserved load, no reserve violations, and minimal curtailment of renewable energy. This assumes sufficient transmission upgrades, expansions and mitigations to accommodate the additional wind and solar resources.

This is operationally achievable with most coal plants operated as baseload must-run units, similar to existing operating practice. It is also achievable if all coal plants are economically committed per MISO market signals, but additional analysis would be required to better understand implications, tradeoffs, and mitigations related to increased cycling duty.

No dynamic analysis was performed for the study scenarios with 50% renewable energy for Minnesota (Scenarios 2 and 2a) due to study schedule limitations and this analysis is necessary to ensure system reliability.

9.3 Annual Energy in the Minnesota-Centric Region

Figure 9-1 shows the annual load and generation energy by type for the Minnesota-Centric region. Comparing Scenarios 1 and 1a (40% MN renewables) with the Baseline,

- Wind and solar energy increases by 8.5 TWh, all of which contributes to bringing the State of Minnesota from 28.5% RE penetration to 40% RE penetration
- There is very little change in energy from conventional generation resources
- Most of the increase in wind and solar energy is balanced by a decrease in imports. The Minnesota-Centric region goes from a net importer to a net exporter.

Comparing Scenarios 2 and 2a (50% MN renewables) with Scenarios 1 and 1a (40% MN renewables),

- Wind and solar energy increases by 20 TWh. Of this total, 4.8 TWh brings the State of Minnesota from 40% to 50% RE penetration and the remainder contributes to bringing MISO from 15% to 25% RE penetration
- Most of the increase in wind and solar energy in the Minnesota-Centric region is balanced by a decrease in coal generation and an increase in net exports to neighboring regions
- Gas-fired, combined-cycle generation declines from 5.0 TWh in Scenario 1 to 3.0 TWh in Scenario 2.

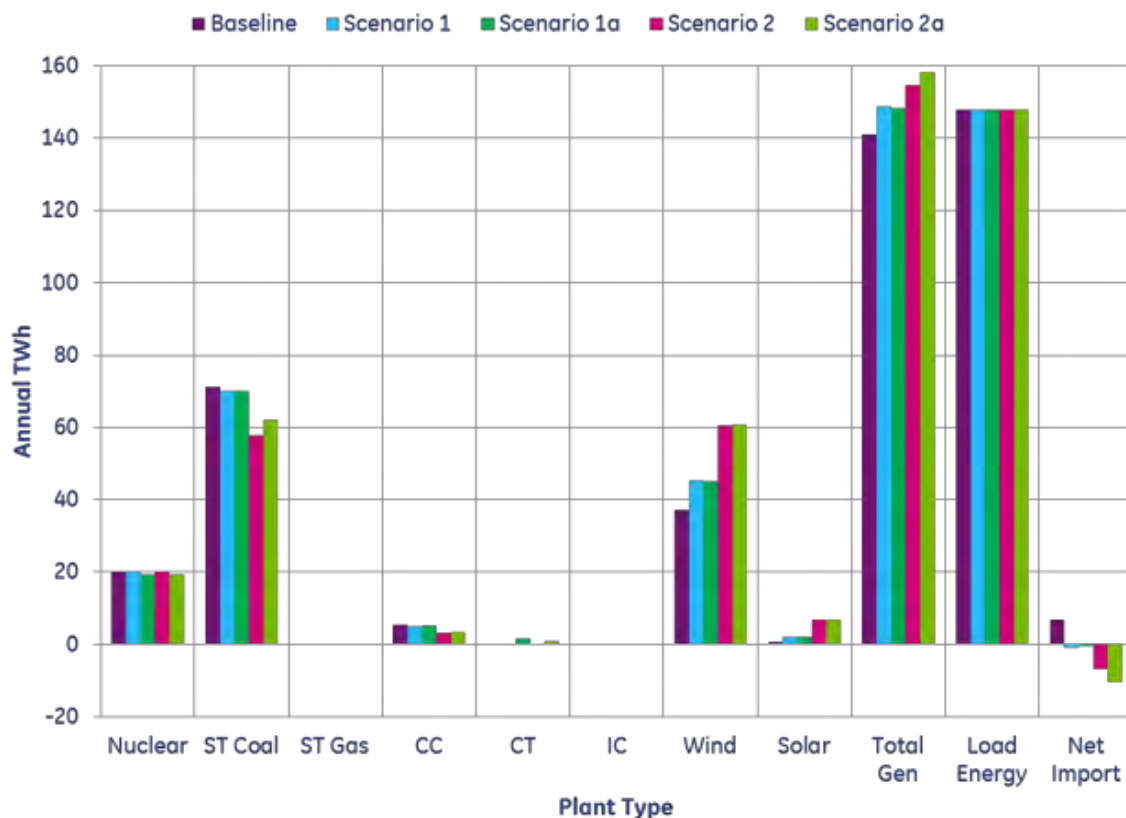


Figure 9-1 Annual Energy by Type in Minnesota-Centric Region for Study Scenarios

9.4 Cycling of Thermal Plants

Most coal plants were originally designed for baseload operation; that is, they were intended to operate continuously with only a few start/stop cycles in a year (mostly due to scheduled or forced outages). Increased cycling duty could increase wear and tear on these units, with corresponding increases in maintenance requirements. Many coal plants in MISO presently are designated by the plant's owner to operate as "must-run" in order to avoid start/stop cycles that would occur if they were economically committed by the market.

Scenarios S1a and S2a assumed that all coal plants in MISO are subject to economic commitment/dispatch (i.e., not must-run) based on day-ahead forecasts of load, wind and solar energy within MISO. Production simulation results show significant coal plant cycling due to economic market signals:

- Small coal units (below 300 MW rating) could have an additional 100 to 200 starts per year, beyond those due to forced or planned outages.
- Large coal units (above 300 MW) could have an additional 20 to 100 starts per year

Scenarios S1 and S2 assumed almost all coal plants would continue to operate as they do today. Coal units were on-line all year (except for scheduled maintenance periods) and were not decommitted during periods of low market prices. The results of these scenarios confirmed that the coal units could remain must-run with minor impacts on overall operation of the Minnesota-Centric

region. Coal plant owners could choose to continue the must-run practice to avoid the detrimental impacts of increased cycling as wind and solar penetration increases. Doing so would likely incur some additional operational costs when energy prices fall below a plant's breakeven point. Wind curtailment would also be about 0.5% higher than if the coal plants were economically committed.

An attractive solution to the coal plant cycling issue may exist between the two bookend cases analyzed in this study. Scenarios 1a and 2a assumed that unit commitment was determined on a day-ahead basis, using day-ahead forecasts of wind and solar energy. The result was a high number of start/stop cycles of coal plants, sometimes with down-times of less than 2 days. If the unit commitment process was modified to use a longer term forward market (say 3 to 5 days ahead), then coal plant owners could adjust their operational strategy to consider decommitting units when prolonged periods of high wind/solar generation and low system loads are forecasted. A forward market would depend on longer term forecasts of wind, solar and load energy, consistent with the look-ahead period of the market. Although such forecasts would be somewhat less accurate than day-ahead forecasts, the quality of the forecasts would likely be adequate to support such unit commitment decisions.

This study did not examine the economic or wear-and-tear impacts of increased cycling on coal units. Further information on this topic can be found in the NREL Western Wind and Solar Integration Study Phase 2 report¹ and the PJM Renewable Integration Study report².

Combined-cycle (CC) units are better able to accommodate cycling duties than coal plants. Simulation results show that combined cycle units in the Minnesota-Centric region experience from 50 to 200 start/stop cycles per year. Cycling of CC units declines slightly as wind and solar penetration increases. This decline is primarily due to a decrease in CC plant utilization as wind and solar energy increases.

9.5 Curtailment of Wind and Solar Energy

In general, a small amount of curtailment is to be expected in any system with a significant level of wind and solar generation. There are some operating conditions where it is economically efficient to accept a small amount of curtailment (i.e., mitigation of that curtailment would be disproportionately expensive and not justifiable).

Overall curtailment in the Minnesota-Centric region is relatively small in all study scenarios, as shown in Table 9-1. Wind curtailment in Baseline and Scenario 1 is primarily due to local transmission congestion at a few wind plants. This congestion could be mitigated by transmission modifications, if economically justifiable.

Wind curtailment in Scenario 2 is due to system-wide operational limits during nighttime hours, when many baseload generators are dispatched to their minimum output levels. This type of curtailment could be reduced by decommitting some baseload generation via economic market signals. The effectiveness of this mitigation option is illustrated by comparing Scenario 2 (coal units must-run) with Scenario 2a (economic coal commitment). Wind curtailment decreases from 2.14% to 1.60% (reduction of 332 GWh of wind curtailment). Solar curtailment decreases from 0.42% to 0.24% (reduction of 12 GWh of solar curtailment).

¹ http://www.nrel.gov/electricity/transmission/western_wind.html

² <http://www.pjm.com/committees-and-groups/task-forces/irtf/pris.aspx>

Table 9-1 Wind and Solar Curtailment for Study Scenarios

Scenario	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Wind Curtailment	0.42%	1.00%	1.59%	2.14%	1.60%
Solar Curtailment	0.09%	0.00%	0.23%	0.42%	0.24%

Note: Curtailment is calculated as a percentage of available annual wind or solar energy.

9.6 Other Operational Issues

No significant transmission system congestion was observed in any of the study scenarios with the assumed transmission upgrades and expansions. Transmission contingency conditions were considered in both the powerflow analysis used to develop the conceptual transmission system and the security-constrained economic dispatch in the production simulation analysis.

Ramp-range-up and ramp-rate-up capability of the MISO conventional generation fleet increases with increased penetration of wind and solar generation. Conventional generation is generally dispatched down rather than decommitted when wind and solar energy is available, which gives those generators more headroom for ramping up if needed.

Ramp-range-down and ramp-rate-down capability of the MISO conventional generation fleet decreases with increased penetration of wind and solar generation. In Scenario 2, there are 500 hours when ramp-rate-down capability of the conventional generation fleet falls below 100 MW/min. Periods of low ramp-down capability coincide with periods of high wind and solar generation. Wind and solar generators are capable of providing ramp-down capability during these periods. MISO's existing Dispatchable Intermittent Resource (DIR) process already enables this for wind generators. It is anticipated that MISO would expand the DIR program to include solar plants in the future.

9.7 System Stability, Voltage Support, Dynamic Reactive Reserves

No angular stability, oscillatory stability or wide-spread voltage recovery issues were observed over the range of tested study conditions. The 16 dynamic disturbances used in stability simulations included key traditional faults/outages as well as faults/outages in areas with high concentrations of renewables and high inter-area transmission flows. System operating conditions included light load, shoulder load and peak load cases, each with the highest percent renewable generation periods in the Minnesota-Centric region.

Overall dynamic reactive reserves are sufficient and all disturbances examined for Scenarios 1 and 1a show acceptable voltage recovery. The South/Central and Northern Minnesota regions get the majority of their dynamic reactive support from synchronous generation. Maintaining sufficient dynamic reserves in these regions is critical, both for local and system-wide stability.

Southwest Minnesota, South Dakota and at times Iowa get a significant portion of dynamic reactive support from wind and solar resources. Wind and Solar resources contribute significantly to voltage support/dynamic reactive reserves. The fast response of wind/solar inverters helps voltage recovery following transmission system faults. However, these are current-source devices with little or no overload capability. Their reactive output decreases when they reach a limit (low voltage and high current).

Synchronous machines (either generators or synchronous condensers), on the other hand, are voltage-source devices with high overload capability. This characteristic will strengthen the system voltage, allowing better utilization of the dynamic capability of renewable generation. The mitigation methods discussed below, namely stiffening the ac system through new transmission or synchronous machines, will also address this concern.

Local load areas, such as the Silver Bay and Taconite Harbor area, require reactive support from synchronous machines due to the high level of heavy industrial loads. If all existing synchronous generation in this region is off line (i.e. due to retirement or decommitment), reinforcements such as new transmission or synchronous condensers would be required to support the load.

Dynamic simulation results indicate that it is critical to maintain sufficient system strength and dynamic reserves to support high flows on the Northern Minnesota 500 kV lines and Manitoba high-voltage direct-current (HVDC) lines. Insufficient system strength and reactive support will limit Manitoba exports to the U.S. Existing transmission expansion plans, as modeled in this analysis, address these issues and are sufficient for the anticipated levels of Manitoba exports.

The Manitoba HVDC ties and the 500 kV transmission system in Northern Minnesota require reactive support from synchronous generators, the Dorsey and Riel synchronous condensers, and the Forbes SVC to maintain the expected level of Manitoba exports. Without sufficient reactive reserves, the system could be unstable for nearby transmission disturbances. The current transmission plans, as modeled in this analysis, address this issue.

9.8 Weak System Issues

Composite Short-Circuit Ratio (CSCR) is an indicator of the ability of an ac transmission system to support stable operation of inverter-based generation. A system with a higher CSCR is considered strong and a system with a lower CSCR is considered to be weak. CSCR is calculated as the ratio of the composite short-circuit MVA at the points of interconnection (POI) of all wind/solar plants in a given area to the combined MW rating of all those wind and solar generation resources.

Low CSCR operating conditions can lead to control instabilities in inverter-based equipment (Wind, Solar PV, HVDC and SVC). Instabilities of this nature will generally manifest as growing voltage/current oscillations at the most affected wind or solar plants. In the worst conditions (i.e., very low CSCR), oscillations could become more wide-spread and eventually lead to loss of generation and/or damage to renewable generation equipment if not adequately protected against such events.

This is a relatively new area of concern within the industry. The issue has emerged as the penetration of wind generation has grown. Understanding of the fundamental stability issues is rapidly growing as more wind plants are being installed in regions with weak ac systems. Equipment vendors, transmission planners and consultants are all working to gain a better understanding of the issues. Modeling and simulation tools have already been developed to enable detailed analysis of the phenomena. Wind and solar inverter control systems are being modified to improve weak system performance.

Synchronous machines (either generators or synchronous condensers) contribute short-circuit strength to the transmission system and therefore increase CSCR. Therefore, system operating conditions with more synchronous generators online will have higher CSCR. Also, stronger transmission ties (additional transmission lines or transformers, or lower impedance transformers) between synchronous generation and regions of wind and solar generation will increase CSCR. SVCs and STATCOMs do not contribute short-circuit current, and because they are electronic converter based devices with internal control systems similar to wind/solar inverters, their presence in a weak system region could further reduce the effective CSCR and exacerbate the control system stability issues that occur in weak system conditions.

There are two general situations where weak system issues generally need to be assessed:

- Local pockets of a few wind and solar plants in regions with limited transmission and no nearby synchronous generation (e.g. plants in North Dakota fed from Pillsbury 230 kV near Fargo).
- Larger areas such as Southwest Minnesota (Buffalo Ridge area) with a very high concentration of wind and solar plants and no nearby synchronous generation

This study examined the sensitivity of weak system issues in Southwest Minnesota. Observations are as follows:

The trouble spots identified in this analysis are not very sensitive to existing synchronous generation commitment. While there is very little synchronous generation within the area, the region is supported by a strong networked 345 kV transmission grid. Primary short circuit strength is from a wide range of base-load units in neighboring areas, and interconnected via the 345 kV transmission network. Commitment, decommitment or outages of individual synchronous generators do not have significant impact on CSCR in these identified areas.

Transmission outages will lower system strength and make the issue worse. When performing CSCR and weak system assessments as wind and solar penetration increases, it will be prudent to consider normal and design-criteria outages at a minimum (i.e, outage conditions consistent with MISO reliability assessment practices).

9.9 Mitigations

There are two approaches to improving wind/solar inverter control stability in weak system conditions:

- To improve the inverter controls, either by carefully tuning the equipment control functions or modifying the control functions to be more compatible with weak system conditions. With this approach, wind/solar plants can tolerate lower CSCR conditions.
- To strengthen the ac system, resulting in increased short-circuit MVA at the locations of the wind/solar plants. This approach increases CSCR.

The approaches are complementary, so the ultimate solution for a particular region would likely be a combination of both.

Mitigation through Wind/PV Inverter Controls

Standard inverter controls and setting procedures may not be sufficient for weak system applications. Loop gains of internal control functions inherently increase when system impedance increases, thereby reducing the stability margin of the controllers. Developers and equipment vendors must be made aware when new plants are being proposed for weak system regions so they can design/tune controls to address the issue. Wind plant vendors have made significant progress in designing wind and solar plant control systems that are compatible with weak system applications.

This approach becomes somewhat more difficult when there are wind/solar plants from multiple vendors in one region. The level of analysis requires detailed modeling of all affected wind plants at a level of detail that requires the use of proprietary control design information from the vendors. Vendors are very reluctant to share such data, except with independent consultants who can guarantee strict data security. However, this approach is gaining traction and a few projects have made effective implementations. The key to success is that project developers and equipment vendors must be informed beforehand that a given wind or solar plant will be installed at a weak system location. This enables the appropriate control design studies to be initiated before the project is installed.

In the event that such control-based approaches are not sufficient, it would be possible to further improve weak system performance by employing one or more of the system-level mitigations discussed below.

Mitigation by Strengthening the AC System

CSCR analysis of the Southwest Minnesota region shows that synchronous condensers located near the wind and solar plants would be a very effective mitigation for weak system issues. Synchronous condensers are synchronous machines that have the same voltage control and dynamic reactive power capabilities as synchronous generators. Synchronous condensers are not connected to prime movers (e.g. steam turbines or combustion turbines), so they do not generate power.

Other approaches that reduce ac system impedance could also offer some benefit:

- Additional transmission lines between the wind/solar plants and synchronous generation plants
- Lower impedance transformers, including wind/solar plant interconnection transformers

Series capacitors on transmission lines could be used to increase CSCR and to improve the transmission system's capability to transfer energy out of regions with high concentrations of wind and solar resources. However, series capacitors create subsynchronous frequency resonances in the transmission system which affect the performance of control systems within wind and solar plants. These resonances introduce an additional challenge to wind/solar plant control designs, which must maintain stable operation in the presence of the resonant conditions. Mitigation through "must-run" operating rules for existing generation was found to be not very effective. The plants with synchronous generators are not located close enough to effected wind/solar plants.

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11 APPENDICES

Appendix A1 – AC Input Files

Appendix A2 – Powerflow Case Flow Info

Appendix A3 – Bus Angle Diagrams

Appendix A4 – Contingency Analysis Spreadsheets

Appendix A5 – Maps

Appendix A6 – Transmission Costs

Appendix A7 – HVDC

Note: The Appendices are available upon request from Great River Energy.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

**Minnesota Department of Commerce
Report**

Docket No. E999/CI-13-486

Dated this 5th day of November 2014

/s/Sharon Ferguson

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Energy Efficiency in Minnesota: Information for the U.S. EPA on Draft Rule 111(d) of the Clean Power Plan

Prepared By: Minnesota Department of Commerce Staff

Minnesota has a long history and ongoing commitment to statewide energy efficiency (EE) policies. It is important to note the expansiveness of Minnesota's overarching statewide energy policies when considering development of the State Implementation Plan (SIP) and future compliance with the Clean Power Plan.

While many codified policies have been in place for decades, Minnesota's landmark Next Generation Energy Act (NGEA) was passed in 2007 creating or amending existing statewide policy goals to meet the changing needs of the state. While there was an emphasis on energy conservation and renewable energy within the NGEA, other areas around greenhouse gas emissions, state government energy conservation, reliability administration, and others were addressed. Details of the Next Generation Energy Act can be found in Minnesota Law Chapter 136 (Senate File 145). Since passage of the NGEA, additional laws have been passed establishing new programs and refining existing policies. Below is a comprehensive table of statutory references for energy efficiency programs and policies in the State of Minnesota:

Codified Energy Efficiency Policies and Goals	Statute/Law/Executive Order
Energy Planning and Policy Goals	MN Statute 216C.05
Energy Efficiency and Conservation	MN Statute 216B.16
Recovery of Electric Utility Infrastructure Costs	MN Statute 216B.1636
Energy Conservation Policy Goal	MN Statute 216B.2401
Energy Conservation Improvement	MN Statute 216B.241
Decoupling of Energy Sales From Revenues	MN Statute 216B.2412
State Government Energy Savings Plan	MN Statute 216C.03
Energy Audit Programs	MN Statute 216C.31
Guaranteed Energy Savings Program (GESp)	MN Statute 16C.144
Local Energy Efficiency Program (LEEP)	MN Statute 216C.42 and 216C.43
Rev It Up Program	MN Statute 216C.145 and 216C.146
Trillion Btu Revolving Loan Fund	MN Statute 16B.322
Property Assessed Clean Energy (PACE)	MN Statute 216C.436

Utility Energy Efficiency Programs (Minnesota Conservation Improvement Program)

Goals:

The Next Generation Energy Act of 2007 established an Energy Efficiency Resource Standard (EERS) for electric and natural gas utilities in Minnesota, including investor-owned utilities, electric cooperatives, and municipal utilities (see Minn. Stat. §216B.241 subd 1c.) Under the EERS, utilities are required to develop plans to achieve energy savings equal to 1.5% of gross annual retail sales through conservation improvement programs designed to help their customers improve end-use energy efficiency. The Conservation Improvement Program (CIP) is a statewide program administered by electricity and natural gas utilities that helps Minnesota households and businesses use electricity and natural gas more efficiently. CIP programs promote energy efficient technologies and practices to residential, commercial, and public customers through various means including

Attachment 3

marketing, incentives, and technical assistance. Commerce reviews and approves utility CIP filings to ensure that energy savings are calculated accurately, statutory requirements are met, and programs meet cost-effectiveness standards.

In addition to customer demand-side management, electric utilities are allowed to count savings from electric utility infrastructure (EUI) improvements¹ approved by the Minnesota Public Utilities Commission (MPUC) under Minn. Stat. §216B.1636.² Such savings count toward the 1.5% savings goal on top of a minimum savings goal of 1.0% from end-use efficiency measures, as long as the infrastructure improvements result in increased energy efficiency greater than that which would have occurred through normal maintenance activity.

Utilities may request a lower goal than the 1.5% standard based on a conservation potential study, historical conservation experience and other factors. However, for investor-owned utilities, the Commissioner of Commerce may not approve a savings goal less than 1.0%.

Investment and Cost Recovery:

Under Minnesota Statutes §216B.241 subd. 1c, all Minnesota electric utilities are subject to an annual energy savings goal of 1.5% of annual retail energy sales, excluding sales to customers that have opted out of utility-administered EE programs. State law requires Minnesota electric and natural gas utilities to invest at least 1.5% and 0.5% annually of their gross operating revenues (GOR), respectively, in conservation improvement programs, except that Xcel Energy's electric utility, as an owner of a nuclear generating plant in Minnesota is required to invest at least 2.0% of GOR annually in CIP. Minnesota statutes include mechanisms for IOUs to recover the costs of implementing CIP programs and earn a performance incentive based on the level of savings and amount of net benefits achieved.³ Most IOUs file their status reports as part of larger consolidated filings that include proposed adjustments to CIP cost-recovery riders based on the previous year's expenditures and performance incentive earned. Concurrent with the status report review process, Commerce staff review the proposed cost-recovery adjustments and file recommendations concerning the proposed adjustments to the Commission. After considering Commerce's recommendations and any public comments filed, the Commission then approves the proposed adjustments as is or with modifications. For cooperative and municipal utilities, local utility commissions, boards or city councils determine their own cost recovery mechanisms.

Cost-Effectiveness:

Like many states with ratepayer-funded EE programs, Minnesota requires that the programs meet certain cost-effectiveness standards. Minnesota's standards are based on the standard benefit-cost tests defined in the California Standard Practice Manual⁴ for demand-side programs. At a minimum, utility residential and commercial/industrial portfolio segments must pass the Societal and Utility Cost tests, which compare the cost of EE investments to their benefits to society and the utility, respectively. In addition, no Minnesota utility can be required to make an EE investment that is not cost-effective (M.S. §216B.241 subd. 1c (f)). These cost-effectiveness standards ensure that ratepayer funds are used wisely.

Planning and Reporting:

¹ For example, installing higher than standard-efficiency transformers, low impedance distribution lines, or reconfiguring transmission system to reduce total losses.

² Minn. Stat. §216B.1636 does not apply to municipal or cooperative utilities. However, the Department of Commerce has allowed municipal and cooperative utilities to count qualifying electric utility infrastructure (EUI) project savings towards their CIP goals even though they are not subject to Minn. Stat. §216B.1636.

³ See Minn. Stat. §216B.16, subd. 6b and 6c.

⁴ *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.*

Attachment 3

Unlike many states, all electric utilities in Minnesota are required to run EE programs and are subject to a single annual energy savings goal, including municipal utilities and electric cooperatives (together, “customer-owned” utilities.) Investor-owned utilities file three-year EE plans while customer-owned utilities file one-year plans. All utilities are required to file annual status reports summarizing their actual EE expenditures and achievements annually. The Minnesota Department of Commerce is charged with reviewing and approving utility plans and savings reports. The Minnesota Public Utilities Commission has authority to approve cost recovery of EE expenditures and EE performance incentives for rate-regulated utilities, though Commerce serves as an intervener in such dockets. Local commissions handle cost recovery issues for customer-owned utilities.

Investor-owned utilities (IOU) file triennial CIP plans on June 1; the next triennial plans, for 2017-2019, will be filed on June 1, 2016. Plans filed June 1 are generally approved as is or with modifications by October or November of the same year. Customer-owned utilities (COU) file annual CIP plans on June 1; the next annual plan, for 2016, will be filed on June 1, 2015. COU plans filed by June 1 are generally approved by Commerce on December 1 of the same year. Electric IOUs file annual status reports on April 1 of each year. COUs file their annual status reports on June 1 of each year. After reviewing each status report and any public comments received, Commerce issues a decision to accept the status report or accept with modifications. Minnesota is unique in the large number of utilities implementing DSM programs in the state. About 180 investor- and customer-owned utilities are subject to DSM implementation and reporting requirements. Also, unlike many states, customer-owned utilities are subject to the same energy savings goal, 1.5% of annual retail energy sales, as investor-owned utilities. Minnesota statutes also allow utilities to aggregate their programs under joint action agencies and generation and transmission cooperatives. Under this option, the aggregating agency can elect to be responsible for achieving the 1.5% energy savings goal, rather than each member organization.

To address the challenges of data management across such a large number of actors with multiple layers of program administrative and reporting responsibilities, the State has developed an innovative software platform called ESP® through a public-private partnership with Energy Platforms, LLC. ESP® provides version management, a complete data trail for all transactions, and a publically accessible database of EE data with built-in analytic functions. ESP® is an essential tool for ensuring that utility EE programs are cost-effective, achieving their approved energy savings goals, and meeting the requirements of State law. ESP® is made up of two applications, ESP (operations) and ReportingESP. ESP (operations) is a user-configurable application for program implementation and energy savings tracking. All data within ESP (operations) are private by default, but can be shared with other organizations. All Minnesota utilities have access to the State’s Digital TRM, described above, through ESP (operations). Utilities can also “consume” the Digital TRM Smart Measures from their own tracking systems. Program implementation data within ESP (operations) are at the measure-level. Each measure, as applied, retains application data, savings outputs, and other information attached by the user (such as invoices, work papers, rebate application forms, etc.)

ReportingESP is the State’s designated tool for EE reporting by Minnesota utilities and also serves as a central, publically-accessible database of EE data and utility sales and customer class data. EE data is entered at the program-level in ReportingESP and can be dynamically grouped and analyzed by utility, aggregator, program category, market segment, etc. The State is currently funding the development of web services to allow the automatic transfer of program implementation data from ESP (operation) and other tracking systems. When this effort is completed, EE data flow will be fully automated from start to finish, from project submittal through reporting.

Evaluation, Measurement and Verification for Utility Energy Efficiency:

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As described above, Minnesota utilities report gross energy efficiency achievements annually to Commerce. For prescriptive programs, utilities are expected to use energy savings algorithms derived from Minnesota's statewide Technical Reference Manual (TRM) or utility-specific algorithms approved as part of their efficiency plans. Custom projects generally do not use pre-approved savings algorithms. Commerce staff evaluate a selection of custom projects each year to ensure that appropriate baselines are used, that calculated savings are reasonable, and that sound engineering methodologies are employed.

Large custom projects with estimated annual savings of at least 1 million kWh or 20,000 dekatherms of natural gas require measurement and verification (M&V) plans to be submitted to Commerce for review. The plans must conform to specific M&V protocols developed by Minnesota stakeholders that are based on the International Performance Measurement and Verification Protocol (IPMVP).⁵ Final savings for these projects are ultimately based on the measured savings.

Minnesota's TRM was developed by an independent third-party contractor with input from Commerce and Minnesota utilities. Commerce manages the TRM and has developed a schedule for regular updates to ensure that the TRM reflects current building codes and equipment standards, markets, and technologies. The schedule includes a third-party evaluation and update every three years, coinciding with the filing of the IOU triennial plans, and annual updates to add or drop measures. An advisory committee and technical working groups have been formed and meet regularly to advise Commerce on TRM content, policies, and procedures.

Minnesota's TRM has also been implemented as a cloud-based library of measure calculators on ESP®, a software platform for energy efficiency tracking and reporting developed in part through funding from Commerce. The measure calculator library or "Digital TRM" is accessible to all Minnesota utilities, implementation contractors, and trade allies and is key to the State's effort to collect accurate energy savings data. Use of the Digital TRM provides Minnesota utilities and their partners a common set of rigorously tested calculators for energy savings measures, thereby ensuring that savings are calculated consistently and accurately across the state. The individual measure calculators or "Smart Measures" also package and retain application data, savings outputs, and other project information, providing a complete data trail for each measure as applied in the field. More information on ESP® and the Digital TRM is provided below.

Line Losses from Utility Energy Efficiency Programs:

EPA specifically requests states to explain whether they account for line losses in their EE savings. Minnesota does account for line losses. Savings are first calculated and verified at the meter, then scaled up to the generator using approved line loss factors. Generally speaking, each utility derives its line loss factor(s) by comparing total energy generated and/or purchased to total energy sales. The difference in these two figures represents the line losses, which is then divided by total energy generated and/or purchased to yield a line loss factor. Some utilities use more sophisticated approaches to derive separate residential and commercial line loss factors, and a peak kW line loss factor that represent losses at peak utility system demand.

Historical Utility Efficiency Performance:

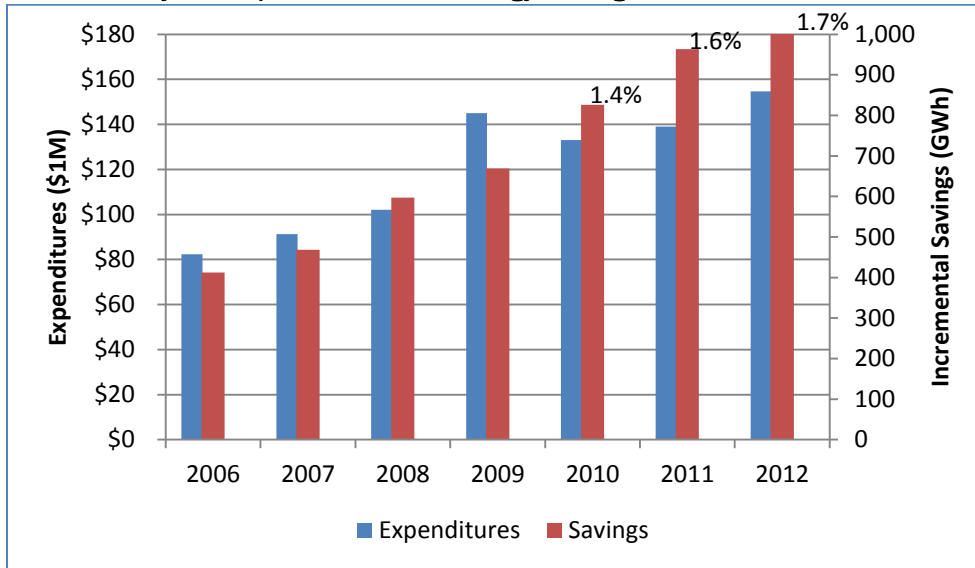
Overall electric and natural gas CIP expenditures and savings have grown significantly since 2006, the earliest year for which Commerce began tracking and reporting individual utility CIP performance. Total electric and natural gas savings over 2011 and 2012 totaled 2,001 gigawatt-hours (GWh) and 5.6 billion cubic feet (bcf), respectively. Combined, these energy savings are equivalent to approximately 12,400,000 million-BTUs (MMBTU). On average, each megawatt-hour (MWh) of electricity saved in Minnesota avoids 1,823 pounds (0.9 tons) of CO₂ emitted to the atmosphere,

⁵ Docket No. E,G999/CIP-06-1591

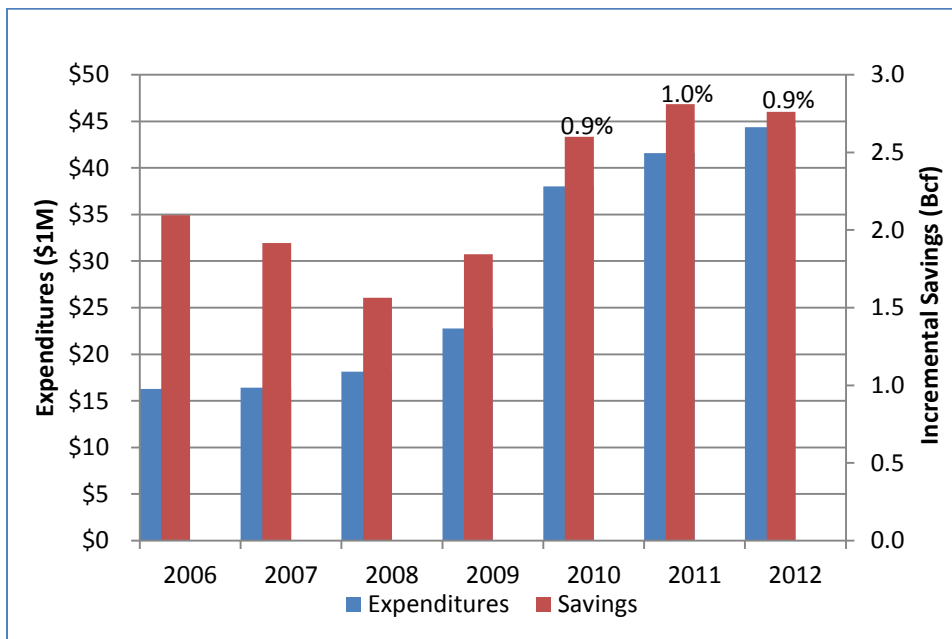
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while each dekatherm (Dth) of natural gas saved avoids 121 pounds (0.1 tons) of CO₂.⁶ The following graphs summarize statewide, aggregator, and utility-level data from 2006 and 2012 and reflect data in Reporting_{ESP} as of April 24, 2014.

Electric Utility CIP Expenditures and Energy Savings from 2006-2012.



Gas Utility CIP Expenditures and Energy Savings from 2006-2012.



⁶ The electric CO₂ emissions rate is provided by the Minnesota Pollution Control Agency to the Minnesota Public Utilities Commission and Minnesota Department of Commerce in Docket No. E,G999/CI-00-1343 and was last updated on March 17, 2009. The gas CO₂ emissions rate of 121 pounds of CO₂ per Dth is a standard emissions factor for natural gas combustion and assumes a properly tuned boiler or furnace such that nearly 100% of fuel carbon is converted to CO₂.

Non-Utility Energy Efficiency and Emerging Programs

While the Conservation Improvement Program may be the largest efficiency program in the state, it is not encompassing of all activity in the state relating to achievement of the State's energy policy goals. There are many energy conservation and efficiency activities that do not include direct utility involvement. Additional energy efficiency programs administered by a state agency in Minnesota include:

Program	Administering Agency	Description
Weatherization Assistance Program (WAP)	Minnesota Department of Commerce	To help low-income families make their homes more energy efficient
Guaranteed Energy Savings Program (GESp)	Minnesota Department of Commerce	Executive Order 11-12 mandates that "In state-owned buildings, state agencies shall adopt cost-effective energy efficiency and renewable energy strategies through the following actions to achieve no less than an aggregate 20 percent reduction in energy use." To attain the savings, the Commissioner of Commerce was to create and staff an Office of Guaranteed Energy Savings Programs to offer a technical assistance program for state agencies, local units of government, and school districts that elect to implement energy-saving and renewable energy improvements through Guaranteed Energy Savings Contracts.
Local Energy Efficiency Program (LEEP)	Minnesota Department of Commerce	*Under Development* State-led process and access to funding to allow non-performance contract energy efficiency projects in local governments, school districts, and other municipal entities.
Rev It Up Program	Minnesota Department of Commerce	*Under development* A statewide revolving loan program will allow for up to \$100 million in revenue bonds to be issued and outstanding at any given time, to provide low-cost, loan-term loans to local units of government, industrial, commercial

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		businesses, or healthcare facilities seeking to finance energy efficiency and/or renewable energy projects.
Trillion Btu	Minnesota Department of Commerce; St. Paul Port Authority	A statewide program, administered by the St. Paul Port Authority (SPPA), assists Minnesota businesses finance energy retrofit or renewable energy projects to reduce energy consumption, with a goal to reduce up to one trillion BTU(s) annually. The program leverages \$15 million in ARRA funds granted to the SPPA by Commerce.
Fix Up Loan Program	Minnesota Housing Finance Authority; Minnesota Department of Commerce	
Southwest Regional Development Commission PACE Program	Minnesota Department of Commerce; Southwest Regional Development Commission	The Southwest Regional Development Commission administers an 18 county regional PACE program. This program enables business owners to place a special assessment against their property to finance and install energy retrofits, and use the accrued operational energy saving to repay the special assessment over a term up to 20 years. This program leverages \$650,000 in ARRA funds granted to the SWRDC by Commerce.
Green Loan for Business Program	Minnesota Department of Commerce; Community Reinvestment Fund	A revolving loan program, administered by the Community Reinvestment Fund (CRF) within the Xcel Energy territory, that provides low-cost loans to businesses seeking financing to install energy retrofits. The program leverages \$500,000 in ARRA funds granted to CRF by Commerce.
Energy Efficiency for Existing 501 (c)(3) Loan Program	Minnesota Department of Commerce; Center for Energy and Environment	A statewide revolving loan program, administered by the Center for Energy and Environment, that provides low-cost loans to non-profit entities seeking financing to install energy retrofits. The program leverages approximately \$225,000 in ARRA funds granted to CEE by Commerce.

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MHFA Fix Up Loan Program	Minnesota Department of Commerce; Minnesota Housing Finance Agency	A statewide residential energy efficiency loan program, administered by MHFA, provides low-cost, unsecured loans to homeowners seeking financing to install energy retrofits in their homes. The MHFA is committed to lending \$10 million in loans by leveraging a \$1 million loan loss reserve fund supported by ARRA funds granted to MHFA by Commerce.
Residential Energy Efficiency Loan Program	Minnesota Department of Commerce; Center for Energy and Environment	Established in 1993, this statewide residential energy efficiency revolving loan program, administered by the Center for Energy and Environment, provides home owners with low-cost financing to install energy efficient retrofits in their homes. The program has leveraged \$1.6 million in Exxon Oil Overcharge funds originally appropriated to Minnesota.
Energy Savings Partnership Program	Minnesota Department of Commerce; St. Paul Port Authority	A statewide revolving loan program, administered by the St. Paul Port Authority, provides low-cost loans to local units of government that pursue energy savings performance contracts (ESPC) under any of the applicable statutes (16C.144, 471.345, or 123B.65). The program leverages a \$2 million loan loss reserve fund supported by ARRA funds.
PACE Program	Minnesota Department of Commerce; St. Paul Port Authority	Property Assessed Clean Energy (PACE) enables business owners to place a special assessment against their property to finance and install energy retrofits (EE & RE) and use the accrued operational energy savings/production to repay the special assessment over a term up to 20 years. Currently, the St. Paul Port Authority administers a statewide "PACE of

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		Minnesota.” Businesses access the program through local governmental units that have authorized a Joint Powers Agreement with the SPPA to administer the program within their local jurisdiction
Sustainable Buildings 2030 (SB2030)	Minnesota Department of Commerce; University of Minnesota Center for Sustainable Building Research	The Minnesota Sustainable Building 2030 (SB 2030) required that on July 1, 2010 all Minnesota State bonded projects – new and substantially renovated – would be required to meet the Minnesota Sustainable Building 2030 (SB 2030) energy standards. The SB2030 - 2010 Energy Standards have been established for over 44 building types. These Energy Standards are based on a 60% energy use reduction from a baseline building of the same type and location with energy performance typical of the existing buildings of that type in 2003 (including buildings built long before 2003).
Buildings, Benchmarking and Beyond (B3)	Minnesota Department of Commerce	Required energy benchmarking tool for reporting the energy usage in all state buildings for use in measuring progress toward a goal of reducing energy consumption by 20 percent ⁷
GreenStep Cities	Minnesota Pollution Control Agency	Minnesota GreenStep Cities is a voluntary challenge, assistance and recognition program that established 28 best practices for use by cities to prioritize and achieve their sustainability and quality-of-life goals.
Energy Codes	Minnesota Department of Labor and Industry	Responsible for the adoption and enforcement of statewide building energy codes. Minnesota is currently in the process of adopting the standards set in the 2012

⁷ See Minn. Stat. §§ 16B.325, subd. 1; 216B.241, subd. 9.; 2001 Minn. Laws, Ch. 212, Art. 1, Sec. 3

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		International Energy Conservation Code (IECC). ⁸
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Evaluation, Measurement and Verification of Non-Utility Energy Efficiency:

State-run energy efficiency programs also use M&V protocols to validate energy savings. The Guaranteed Energy Savings Program (GESp) requires energy service companies (ESCOs) to measure and verify savings annually using best practices outlined by the International Performance Measurement and Verification Protocol (IPMVP) and the Federal Energy Management Program (FEMP). Local units of government entering into a GESp contract are required by the joint powers agreement to provide the annual M&V reports provided by the ESCO as well as enter facility utility information into the statewide B3 benchmarking system.

Programs under development such as the Local Energy Efficiency Program (LEEP) and Rev It Up Community Loan Program will use varying degrees of formal M&V. LEEP is planned to follow IPMVP and FEMP guidelines for post-implementation verification of savings, but since LEEP is not designed as a performance contract, the baseline measurements may not be as robust as a full investment grade audit may otherwise provide. However, any projects will require LGUs to submit annual M&V reports similar to GESp.

LGUs may also enter into performance contracts with ESCOs directly outside the GESp program. They are required to submit the performance contract agreement, which includes calculated annual energy savings, to the Department of Commerce by a variety of state statutes. Commerce may request annual M&V reports from the LGU to track aggregate energy savings through efficiency measures.

As stated in the previous EM&V section, some of these programs will have M&V protocols as built in requirements. It is the goal of the MN Department of Commerce to aggregate these savings through the B3 tool and M&V reporting, and the use of designated software or reporting requirements by the EPA should be avoided.

⁸ <http://www.dli.mn.gov/ccld/codes.asp>